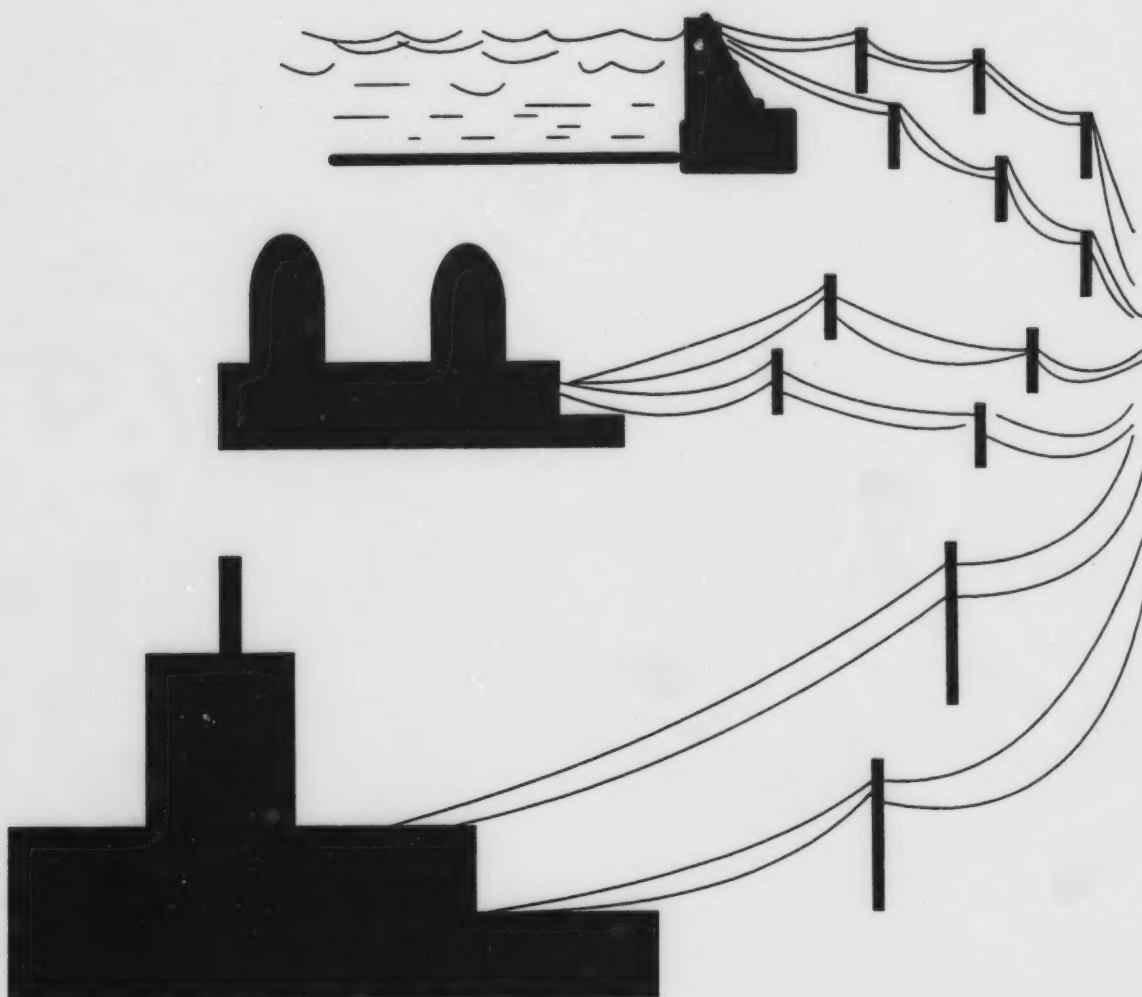


INTER-UTILITY TRADE REVIEW

INTER-UTILITY COOPERATION



**National Energy Board
1992**

INTER-UTILITY TRADE REVIEW

INTER-UTILITY COOPERATION

NATIONAL ENERGY BOARD

1992

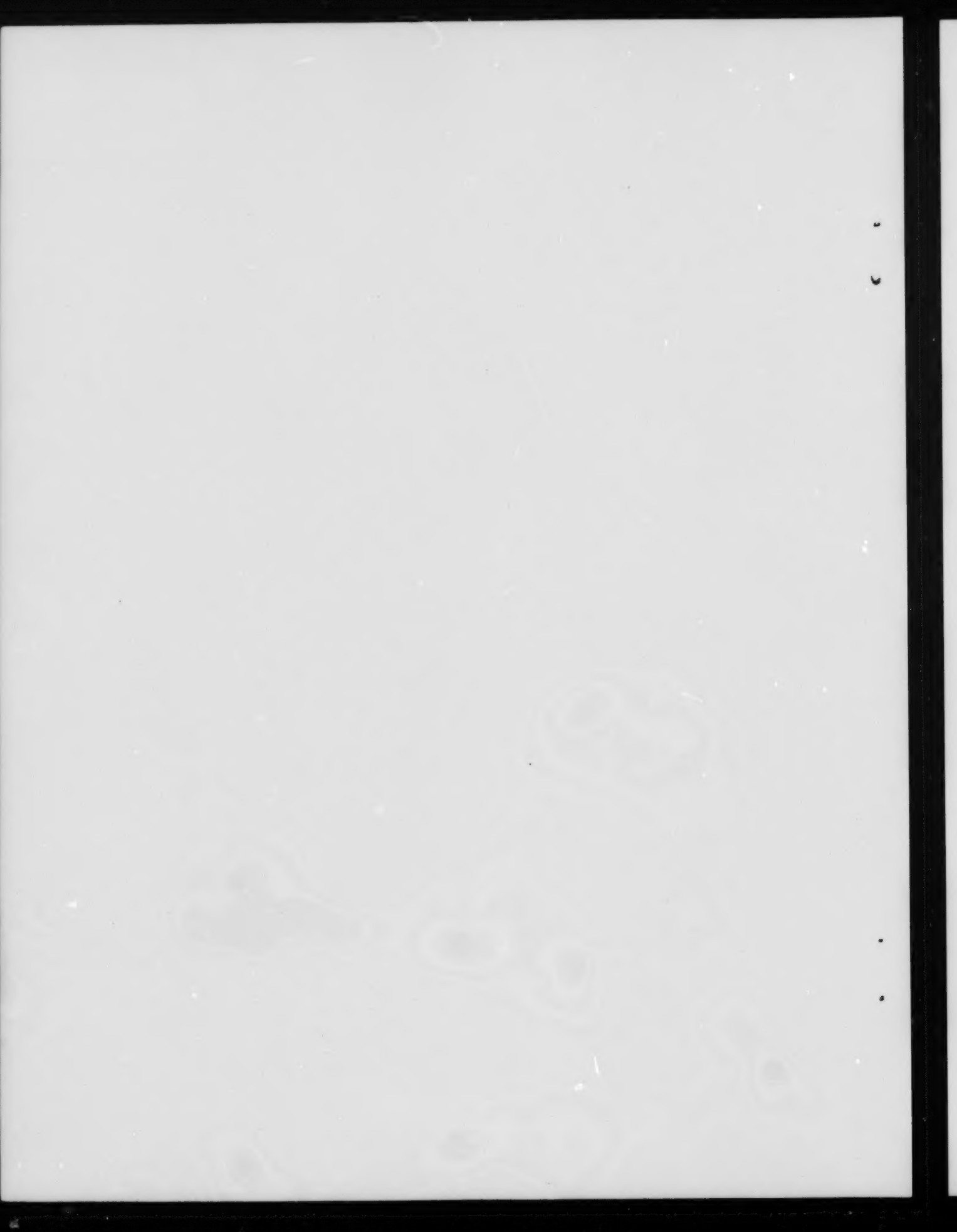


TABLE OF CONTENTS

	Page
Key Findings and Options	(i)
Foreword	(vi)
Acknowledgements	(vii)
Outline of Report	(viii)
 1. The Canadian Interconnected Systems	 1-1
1.1 Introduction	1-1
1.2 The Evolution of the Electricity Supply Industry	1-1
1.3 The Development of Transmission and Interconnected Systems	1-3
1.4 The Existing Industry Structure	1-6
1.5 The Nature of Interprovincial Cooperation	1-8
 2. National Electricity Planning Initiatives	 2-1
2.1 Introduction	2-1
2.2 The Vision of a National Canadian Electricity Grid	2-1
2.3 The National Power Network Study	2-3
2.4 The Provinces Take the Initiative	2-6
2.5 The IPACE Study	2-7
2.6 Conclusions	2-11
 3. Experiments in Regional Planning	 3-1
3.1 Introduction	3-1
3.2 Multi-Provincial Initiatives	3-1
3.2.1 The Western Grid	3-1
3.2.2 The Eastern Grid	3-6
3.2.3 The Maritime Energy Corporation	3-12
3.3 Bilateral Initiatives	3-24
3.3.1 Introduction	3-24
3.3.2 New Brunswick - Nova Scotia Initiatives	3-25
3.3.3 Fundy Tidal Power	3-27

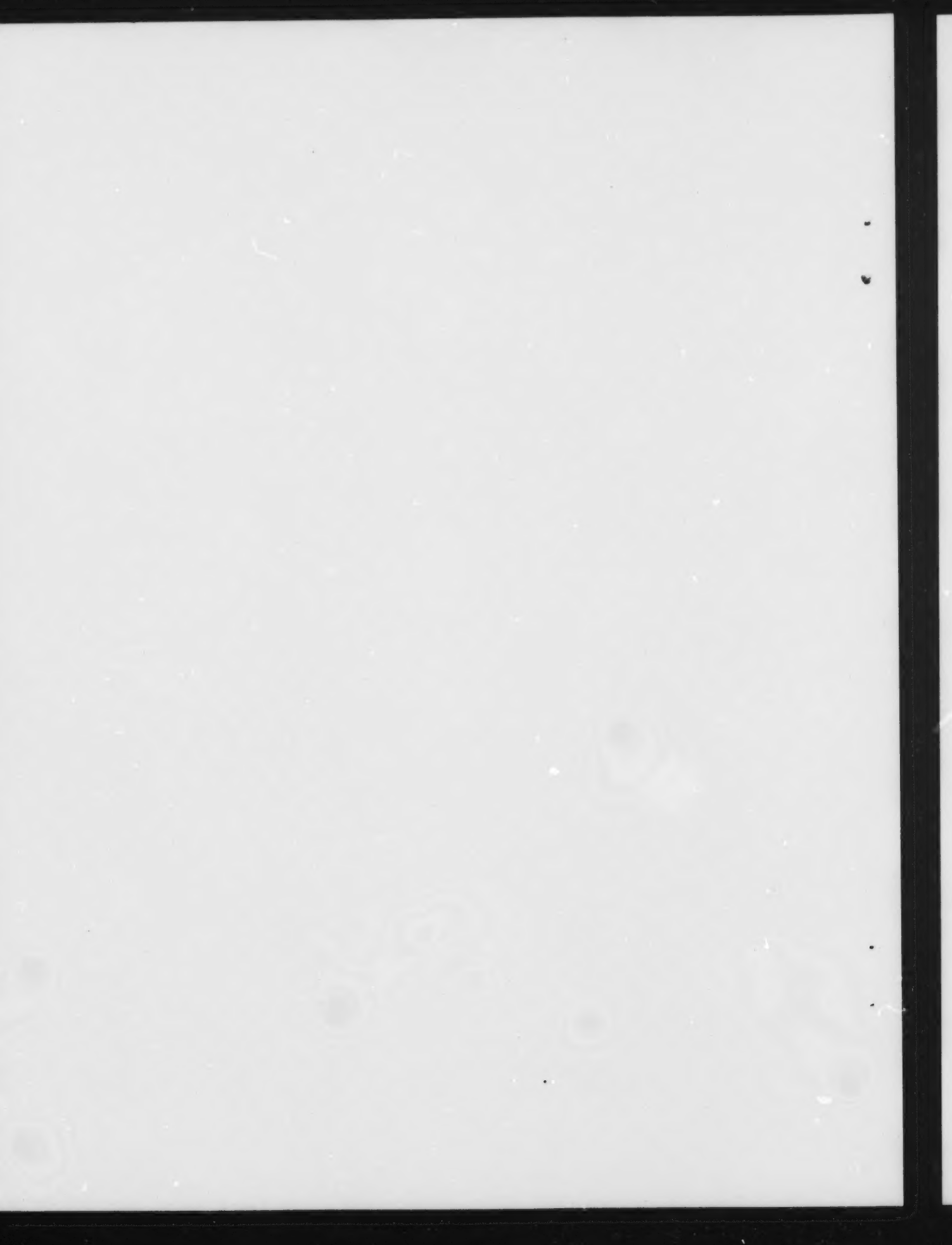


TABLE OF CONTENTS (continued)

3.3.4 Nelson River Transmission Initiatives	3-29
3.3.5 Newfoundland (Labrador) - Québec Initiatives	3-30
3.3.6 Lower Churchill Development Corporation	3-33
3.3.7 New Brunswick - Québec Initiatives	3-34
3.3.8 New Brunswick - Prince Edward Island Initiatives	3-36
3.3.9 Alberta - British Columbia Initiatives	3-37
3.3.10 Alberta - Saskatchewan Initiatives	3-39
3.4 Conclusions	3-39
 4. The Nature and Benefits of Inter-utility Cooperation	 4-1
4.1 Introduction	4-1
4.2 Dimensions of Inter-utility Cooperation	4-1
4.3 Purposes of Inter-utility Cooperation	4-3
4.4 The Functional Dimension	4-3
4.4.1 Operational Arrangements	4-4
4.4.2 Planning Arrangements	4-7
4.5 Arrangements Involving Wheeling	4-11
4.5.1 Basic Kinds of Wheeling	4-12
4.5.2 Institutional Modes to Effect Wheeling	4-13
4.6 Cooperative Mechanisms	4-14
4.7 The Time Dimension	4-16
4.8 The Economic Dimension	4-17
4.9 The Environmental Dimension	4-17
4.10 The Geographic Dimension	4-18
4.11 Conclusions	4-18
4.12 Benefits and Constraints	4-18
4.12.1 Benefits	4-18
4.12.2 Constraints	4-20
 5. The Extent of Inter-utility Cooperation in Canada	 5-1
5.1 Introduction	5-1
5.2 Interconnections	5-1
5.3 Existing Cooperation Agreements	5-6
5.4 Future Cooperation Initiatives	5-9
5.5 The Role of Independent Power Producers	5-18
5.6 Actions to Encourage Future Cooperation Initiatives	5-21
5.6.1 Actions by Utilities	5-21

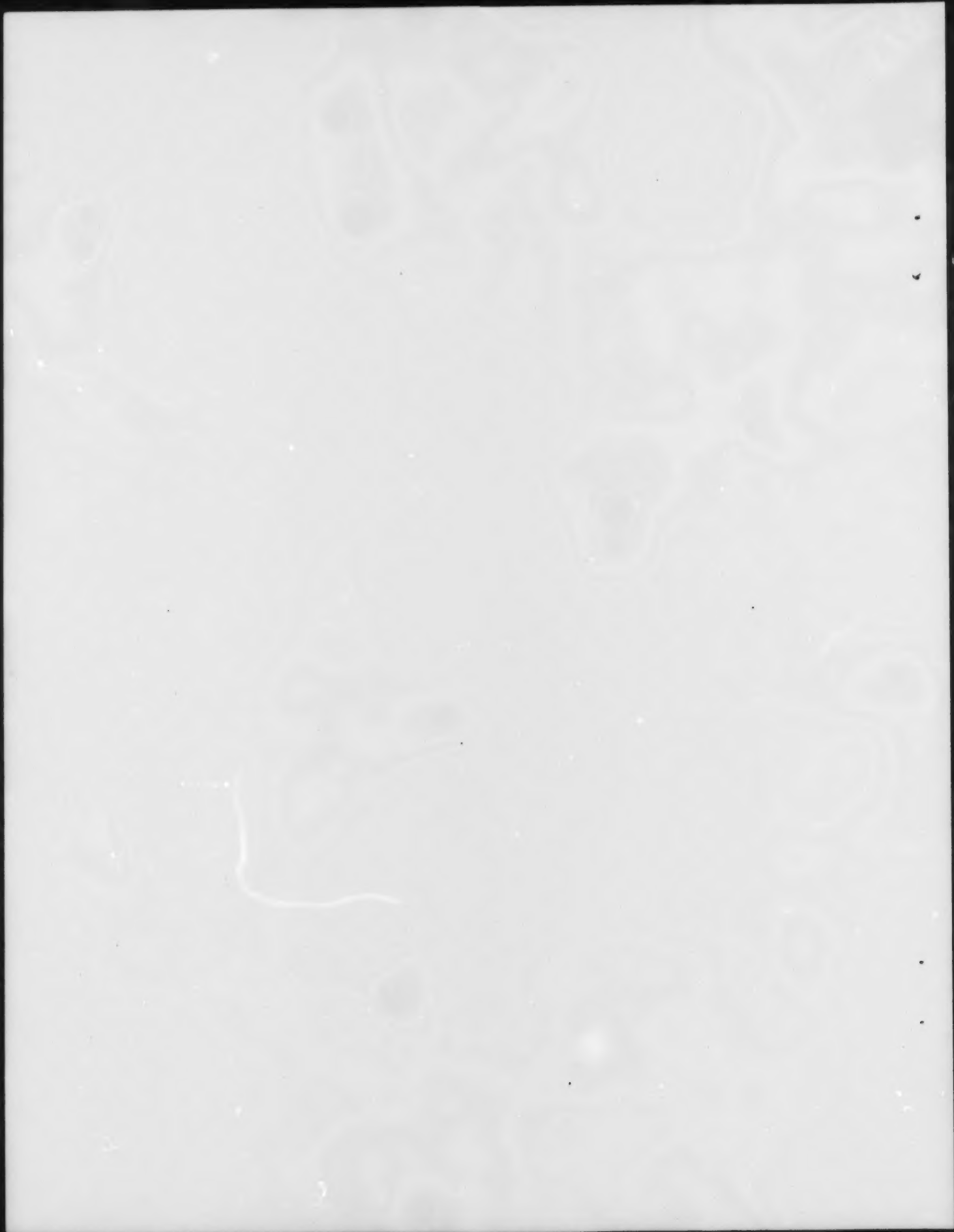


TABLE OF CONTENTS (continued)

5.6.2	Actions by the Federal Government	5-24
5.6.3	Actions by Provincial Governments	5-24
5.6.4	Actions by Both Levels of Government	5-25
5.7	Responses from Provincial Governments and Others	5-25
5.8	Conclusions	5-26
6.	Opportunities for Further Inter-utility Cooperation	6-1
6.1	Introduction	6-1
6.2	Regional Analyses	6-1
6.2.1	Region No. 1 - British Columbia/Alberta/Pacific Northwest/California	6-3
6.2.2	Region No. 2 - Saskatchewan/Manitoba/US Midwest	6-10
6.2.3	Region No. 3 - Manitoba/Ontario/Québec/New York/ECAR	6-13
6.2.4	Region No. 4 - Ontario/Québec/Newfoundland/New York/New England	6-17
6.2.5	Region No. 5 - Québec/New Brunswick/PEI/Nova Scotia/New England	6-21
6.3	Assessment of Benefits from Regional Cooperation and Development	
	Opportunities	6-26
6.3.1	Sharing of Generation Reserves	6-27
6.3.2	Seasonal Diversity Exchanges and Summer Sales	6-28
6.3.3	New Interconnections	6-28
6.3.4	Long-Term Firm Trade	6-29
6.3.5	Summary of Estimated Benefits	6-29
6.4	Other Illustrations of Potential Benefits from Cooperation	6-36
6.4.1	Responses to Board Questionnaire	6-36
6.4.2	B.C. Hydro/Alberta Coordination Study	6-36
6.4.3	Western Electric Utility Cooperation	6-37
6.4.4	Maritime Energy Corporation	6-37
6.5	Conclusions	6-38
7.	Measures to Enhance Cooperation	7-1
7.1	Introduction	7-1
7.2	Federal/Provincial Authority	7-1
7.2.1	Provincial Powers	7-1
	7.2.1.1 Provincial Utility Regulation	7-2
	7.2.1.2 Provincial Non-utility Regulation	7-6
	7.2.1.3 Conclusions	7-7
7.2.2	Federal Powers	7-8



TABLE OF CONTENTS (continued)

7.2.2.1 Federal Legislation	7-8
7.2.2.2 Federal Policies	7-11
7.2.2.3 Conclusions	7-13
7.3 Recapitulation of Findings	7-14
7.3.1 Historical Perspective	7-14
7.3.2 Existing Inter-utility Cooperation	7-16
7.3.3 Role of Independent Power Producers	7-17
7.4 Opportunities for Further Cooperation	7-18
7.5 Observations on Enhanced Cooperation	7-20
7.6 Options Available to Enhance Cooperation	7-25
7.6.1 Option #1: Continue Voluntary Cooperation	7-25
7.6.2 Option #2: Voluntary Cooperation with Federal Monitoring	7-25
7.6.3 Option #3: Establish Voluntary Regional Planning Entities	7-25
7.6.3.1 Scope of Entities	7-26
7.6.3.2 Responsibilities of Entities	7-27
7.6.3.3 Membership of Entities	7-27
7.6.4 Option #4: Establish Regional Planning Entities with Mandated Federal Power	7-28
7.7 Involvement by Participants in the Regional Entities	7-28
7.7.1 Utility Involvement	7-28
7.7.2 Provincial Involvement	7-29
7.7.3 Federal Involvement	7-29
7.8 Conclusions	7-30



List of Tables

Page

Table 1.1 - Installed Generation Capacity by Fuel Type and Province, 1989	1-11
Table 1.2 - Chronology of Regional Interconnections	1-12
Table 1.3 - Major Electric Utilities by Province	1-13
Table 5.1 - Capacity of Existing and Potential Interprovincial Interconnections	5-4
Table 5.2 - Capacity of Existing and Potential International Interconnections	5-5
Table 5.3 - Proposed Assisting Actions for Future Initiatives	5-22
Table 6.1 - Summary of the Potential Net Benefits by Regions from Cooperation and Joint Developments	6-30
Table 6.2 - Summary by Type of Long-Term Net Benefits from Enhanced Inter-utility Cooperation	6-35

List of Figures

Figure 5.1 - Existing and Potential Interprovincial and International Interconnectors above 69 kV	5-2
Figure 5.2 - Transfer Capabilities of Existing and Potential Interprovincial and International Interconnections above 69 kV and Provincial Installed Generating Capabilities (MW)	5-3
Figure 6.1 - Regions used to Assess Cooperation and Development Opportunities	6-2
Figure 6.2 - Nominal LUEC in mills/kW.h for Selected North American Generating Facilities for In-service in the Year 2000	6-4
Figure 6.3 - Generation Supply Growth Potential in Canada and Selected U.S. States by Year 2000	6-5
Figure 6.4 - Nominal Fuel LUEC in mills/kW.h for Selected North American Generating Facilities for In-Service in the Year 2000	6-6
Figure 6.5 - Cooperation and Development Opportunities for Region 1	6-7
Figure 6.6 - Cooperation and Development Opportunities for Region 2	6-11
Figure 6.7 - Cooperation and Development Opportunities for Region 3	6-14
Figure 6.8 - Cooperation and Development Opportunities for Region 4	6-18
Figure 6.9 - Cooperation and Development Opportunities for Region 5	6-22

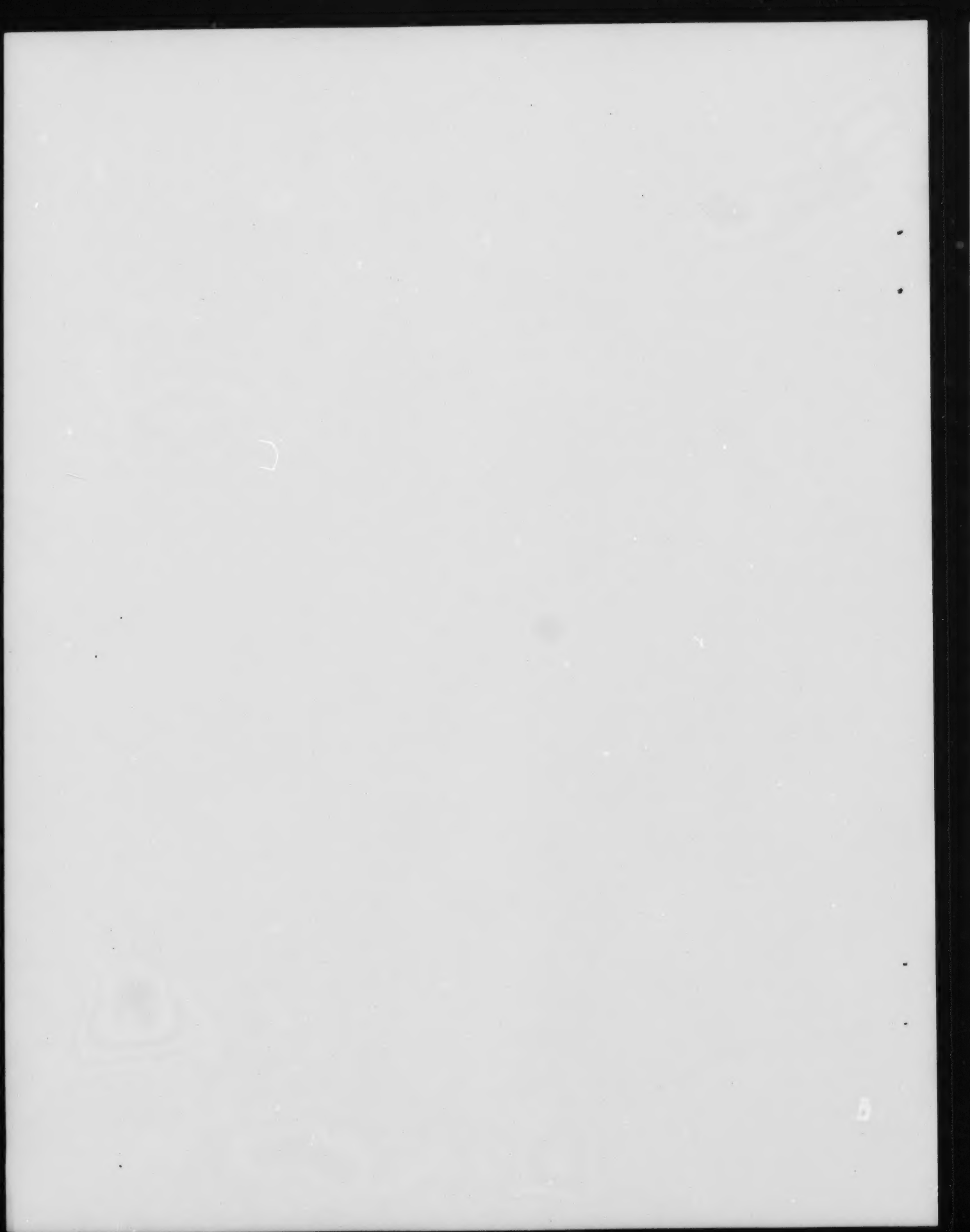


INTER-UTILITY TRADE REVIEW

INTER-UTILITY COOPERATION

NATIONAL ENERGY BOARD

1992



KEY FINDINGS AND OPTIONS

The following paragraphs summarize the key findings emanating from the Board's review of measures to increase interprovincial trade in electricity which was undertaken at the request of the Minister of Energy, Mines and Resources. Also included are a range of possible options available to achieve additional trade through enhanced inter-utility cooperation.

Under the Constitution Act, legislative authority over management of natural resources, and the generation, transmission and distribution of electricity, rests primarily with the provinces. The provinces have jurisdiction over generating facilities within their own borders and over intraprovincial transmission grids. In all provinces, development of new generation and transmission facilities by electric utilities and others, as well as the price of electricity to utility customers, is controlled by the provincial governments.

The mandate of the National Energy Board with regard to electricity supply is restricted under the NEB Act mainly to regulation of exports and to facilities related to international and designated interprovincial transmission lines.

In just over a century, the electricity supply industry in Canada has evolved from a series of isolated generating units supplying local demands, into province-wide interconnected systems. Typically, within each province, the entire interconnected generation and transmission system is now planned, developed and operated in a fully integrated manner, often by a single provincially-owned utility. In general, the industry structure that has emerged has led to the efficient, reliable supply of electricity within each province. The fundamental principle on which the provincial systems are planned and operated is that of providing a secure supply of electric power to customers at least cost.

Historically, utilities have met this objective almost exclusively through the development of utility-owned, supply-side options (i.e. building and operating generating plant and transmission lines). However, the traditional process of planning, development and operation within the industry is changing in several, quite profound ways. In some provinces, independent power producers (IPPs) are now competing to supply power to provincial grids. Also, utilities are moving towards a process of least-cost Integrated Resource Planning (IRP) in which a combination of supply-side and demand-side options is considered for development.

At the same time, before approving new generating projects, some provincial regulators are beginning to require utilities to demonstrate that they have considered all potential supply-side

(ii)

options (including utility-owned generation, IPPs and power purchases from other utilities), as well as demand-side management opportunities. The environmental impact of power production and transmission is becoming an increasing concern of governments, utilities and the public at large, and this is reflected in the more stringent environmental regulations that are now in place. As a result, environmental concerns are affecting the selection of generating technology, the fuel used, and the cost and siting of new facilities, as well as the choice between supply-side and demand-side alternatives.

Although the principal focus of Canadian electric utilities has been to meet in-province demands, they have sought to gain added security and economic benefits through ties with other systems. Thus, a certain degree of cooperation already exists between neighbouring utilities in Canada, and between Canadian and U.S. utilities, and these activities result in benefits to utility customers. However, there is potential for further significant benefits to be achieved if the present base of cooperation is expanded.

As part of the current review a series of analyses was undertaken to quantify the long-term net benefits that might be available from enhanced inter-utility cooperation, from both interprovincial and international perspectives. The analyses were carried out using information obtained from the utilities, as well as other published data, and provide order-of-magnitude estimates of the benefits that could be achieved. The estimates were made assuming the benefits would start in the year 2000. They were made in projected year 2000 dollars, and the present value calculated to the year 2000 using a real annual discount rate of 6 percent. The following table summarizes these estimates:

<u>Type of Transaction</u>	<u>Estimated Benefit</u> (\$ billion)
Seasonal Diversity Exchanges/Summer Sales	5.8 to 6.4
New Interconnections	0.6
Long-term Firm Sales	<u>16.6 to 25.5</u>
TOTAL	<u>23.0 to 32.5</u>

The realization of some of the seasonal diversity/summer sales and long-term firm sales transactions that were identified would involve the use of wheeling.

(iii)

In addition, an estimate was made in the parallel study on Transmission Access and Wheeling of the short-term benefits that would result from increased economy energy transfers, including bilateral exchanges and wheeling among non-adjacent systems, in eastern Canada and the northeastern United States (Ontario, Québec, the Maritimes, New York and New England). The total value of bilateral exchanges available in this region over a five-year period was estimated to be some \$3 billion, expressed in 1990 purchasing power. By allowing access to wheeling services these benefits were estimated to increase by up to 10 percent. Opportunities for similar short-term energy transfers are likely to exist in other regions.

These estimates demonstrate that the potential benefits from increased inter-utility cooperation are significant, and warrant continued effort on the part of the electric utilities, as well as by the provincial and federal governments, to achieve them.

Although the results of the analyses show that considerable opportunities exist for greater interprovincial cooperation, a significant portion of the total benefits that would accrue appear to be available from increased electricity exports to the United States. In order to maximize the benefits from international trade it might be desirable for Canadian entities to form partnerships. Such cooperation within Canada might have the effect of increasing the quantity and quality of exports, thus increasing their value.

Since jurisdiction over electricity supply lies primarily with individual provinces, it is largely within their existing powers, through their control over the industry, to promote increased trade in electricity by greater cooperation. The provinces and utilities could help achieve such cooperation by encouraging and engaging in planning on a regional basis, with the potential for lower power costs for consumers. Also, in some cases, there could be beneficial environmental impacts resulting from a systematic approach to regional planning, and these may well become increasingly important.

Much progress has been achieved within North America as a whole to ensure and safeguard the reliability of supply of interconnected systems. This has been done over many years through voluntary adherence by the utilities to systems planning criteria and operating codes of practice developed under the aegis of the North American Electric Reliability Council (NERC). Although engaging in greater inter-utility cooperative activities in order to realize increased economic benefits is desirable, these benefits should not be obtained at the expense of reliability of service.

From the Board's findings, the following options to achieve enhanced inter-utility cooperation have been identified. Although they are by no means exhaustive, it is believed that they provide a reasonable range of alternatives for consideration by interested parties.

OPTION 1 - Continue Voluntary Cooperation

This review has demonstrated that Canadian utilities currently cooperate and trade both inter-provincially and internationally. Under this option, the utilities would continue to enter into voluntary negotiations, usually on a utility-to-utility basis, to increase trade as they see opportunities arise. The agreements reached between the utilities would be made under existing provincial and federal regulations and policies. The federal government would participate in the study and implementation of future interprovincial and international projects within the context of current federal policies.

OPTION 2 - Voluntary Cooperation with Federal Monitoring

With this option, the utilities and provinces would continue to act as they do now but the federal government would undertake to monitor progress on cooperation on a regular basis. This could take the form of updates to parts of this review, with particular focus on the improvements in cooperation that had taken place, as well as on areas where there had been no progress. These reports would be public documents and would be available for use by both levels of government, utilities, and other stakeholders and interested parties in deciding on future courses of action.

OPTION 3 - Establish Voluntary Regional Planning Entities

Under this option, Canadian utilities, together with their neighbours in the U.S., would establish, on a voluntary basis, regional planning entities whose main objective would be to identify opportunities for wider cooperation among them. The scope of such entities could vary widely but, ultimately, they could engage in least-cost integrated resource planning on a regional basis and fully coordinated systems operation in a tight pool. These entities would provide a focus on "economic" improvements related to the planning, development and operations of interconnected systems, in a similar way that the NERC regional councils now afford on "reliability" matters. They might also focus on "environmental" improvements that could be achieved by regional cooperation. The federal government's role in the regional planning process would be to participate with the provinces and the utilities in developing policies and mechanisms to achieve, on an equitable basis, transmission access and wheeling services by utilities and IPPs across provincial and international boundaries. Among other things, the federal government could assist the regional planning entities in establishing consistent goals and economic planning parameters to be used by them in the analysis of alternatives, and continue to act as a facilitator to encourage increased trade and monitor the progress made.

(v)

OPTION 4 - Establish Regional Planning Entities with Mandated Federal Power

This is similar to Option #3, except that the federal government would exercise those powers that it might have to resolve disputes in matters involving international electricity trade, and both international and interprovincial wheeling.

FOREWORD

The federal government's "Canadian Electricity Policy" dated September 1988 focused on new initiatives with respect to the regulation of electricity exports, and the construction and operation of international power lines. In that year the federal government also established an Energy Options Advisory Committee whose purpose was to canvass Canadians in order to develop a comprehensive energy options plan into the next century. In the fall of 1988, the Committee released its report entitled, "Energy and Canadians: Into the 21st Century", which stated that "the Government of Canada has a crucial leadership role to play in eliminating barriers to interprovincial trade". The Committee made two particular suggestions:

- electrical energy generation should be organized on a cooperative interprovincial scale when economically viable; and
- the Government of Canada should articulate the conditions under which one province has a right to access, on a business basis, another province's electricity corridor or electrical grid for the purpose of transmitting electricity to a market not adjacent to the first province.

The federal government acknowledged that a number of difficult practical and jurisdictional questions must be addressed before it could decide whether it was necessary to take specific policy actions in these areas. Accordingly the federal Minister of Energy, Mines and Resources requested the National Energy Board (the Board) to review the role that the federal government might play in eliminating the barriers to interprovincial electricity trade. Specifically the Minister asked the Board to undertake a review and report on possible measures to:

- enhance interprovincial trade in electricity;
- encourage greater cooperation between utilities in systems planning and development; and
- enable buyers and sellers of electricity to obtain commercial access to available transmission capacity through intervening provinces for wheeling purposes.

In undertaking this review, the Board decided to carry it out along two separate tracks. The first focussed on inter-utility cooperation and is the basis for this report. The second addressed questions relating to wheeling and transmission access and forms part of a second report.

It was clear to the Board that an undertaking of this magnitude would require the gathering and analysis of much data and information. Accordingly, the Board undertook a series of initiatives to build the required information base. These included the preparation by Board staff of a paper entitled "Inter-utility Cooperation: A Conceptual Framework", as well as an "Inter-utility Cooperation Questionnaire" designed to elicit information concerning the cooperative arrangements that exist or might exist among any particular group of Canadian utilities. These documents were sent to provincial governments, electric utilities and other interested parties in March 1990. In addition, Board staff undertook reviews of past approaches to national and regional electricity planning, and conducted assessments of the comparative supply costs of generation to obtain an indication of the potential for enhanced inter-utility cooperation among Canada's electric utilities. These reviews and assessments, together with the Board staff's synthesis of responses to the questionnaire, were forwarded to the provinces and Canadian utilities in December 1990 for their examination and comment. A series of meetings was held in the spring/summer of 1991 between Board staff and representatives from the provinces and utilities to review the material provided. Information arising from these discussions and comments received subsequently were incorporated into, and form an integral part of, this report.

The Board, as part of the consultative process, intends to solicit comments from interested parties on the results of these preliminary investigations. These consultations will lay the foundation for a productive dialogue on the options available to enhance interprovincial trade in electricity.

ACKNOWLEDGEMENTS

This report would not be possible without the full participation of the provincial governments, Canadian electrical utilities and other interested parties. The Board gratefully acknowledges their contributions.

OUTLINE OF REPORT

Chapter 1 describes the evolution of the Canadian interconnected electric systems, the existing structure of the industry, the relative size of each provincial system, and the principal utilities operating in each province.

Chapter 2 examines previous attempts by the federal and provincial governments to promote the concept of a "national grid" which would have interconnected electric systems from coast to coast by means of extra high voltage transmission lines. Separate sections discuss the two major proposals that have been advanced over the past thirty years: one in the sixties; and the other in the seventies. It outlines the difficulties encountered in promoting a national entity which would have transcended the separate interests of the provinces and the utilities under their purview.

Previous attempts to promote multi-provincial or regional, rather than national, electric systems or institutions are examined in Chapter 3. The main examples studied are the attempts to create a western grid, an eastern grid and a Maritime grid. The chapter emphasizes the difficulties encountered in trying to establish regional entities for the planning and development of electricity generation and transmission. It then goes on to examine interprovincial bilateral initiatives that have taken place, many of which have been supported by the federal government, and attempts to explain the reasons for their success.

To better understand what is meant by inter-utility cooperation, Chapter 4 develops a generic framework for cooperation that serves to define the nature and benefits involved. The chapter describes the kinds of arrangements which have evolved, namely: intraprovincial; interprovincial; and international. It next defines the different classes of cooperation. These range from short-term operational coordination to cooperation in long-term systems planning. For each of these different classes, several categories of cooperation are defined. Finally, the chapter provides a qualitative discussion of the benefits of, and constraints to, increased cooperation.

The inter-utility cooperation framework described in Chapter 4 formed the basis for a questionnaire to provincial governments, electric utilities and other interested parties. Based on responses to the questionnaire, Chapter 5 describes current inter-utility cooperation in Canada. It looks at existing national and international arrangements, as well as proposed arrangements currently under active discussion. Finally, it examines possible measures that could be taken by the federal and provincial governments, and the utilities to encourage such future initiatives.

While the preceding chapters examine inter-utility cooperation principally from a qualitative perspective, Chapter 6 describes the study carried out to quantify the potential cooperation and regional development opportunities that exist. Recognizing that most Canadian electric utilities

are interconnected both interprovincially and internationally, the study took into account not only opportunities for increased interprovincial trade but also the potential for international trade. Selected provinces and states were grouped together to form, what can be termed, "development regions". Within each region, the long-run generation and associated transmission costs for particular provinces and states were calculated. These costs were then used to determine the comparative economic advantage or potential negotiating margin between systems in the region from the standpoints of interprovincial and international trade. From these comparisons, general observations and conclusions were drawn about the relative economic potential for, and possible barriers to, increased inter-utility trade. Finally, selected development schemes within regions were analyzed to quantify the potential benefits that might result from enhanced inter-utility cooperation.

Chapter 7 is the concluding chapter of this report. It begins by clarifying the authority of the federal and provincial governments under the Constitution Act with respect to the development and management of electricity generation, transmission and distribution facilities and, in particular, focuses on the initiatives available to the federal government to influence and effect change. It then draws together the central conclusions of the preceding chapters and describes factors that would encourage greater inter-utility cooperation. It then outlines a range of feasible options available for consideration by interested parties, and describes measures that the utilities, and the provincial and federal governments might take to promote increased inter-utility cooperation.



1. THE CANADIAN INTERCONNECTED SYSTEMS



1. THE CANADIAN INTERCONNECTED SYSTEMS

1.1 Introduction

This chapter describes the evolution of the Canadian interconnected electrical systems. It outlines how each province generates electricity, the relative size of each provincial system, and the principal utilities operating in each province.

1.2 The Evolution of the Electric Supply Industry

The first Canadian commercial electric power company was established in Pembroke, Ontario in 1884. At that time, the bulk of the electricity supply came from fossil-fuelled plants located near the centres of demand, as the transmission of electricity was limited to a radius of a few miles, at the low voltages then in use. This was the case for Montréal and Toronto and demand centres in British Columbia and the Prairies. Few cities were as fortunate as Ottawa with a number of nearby water power sites and most had to await the advent of long-distance transmission to receive the benefits of Canada's vast hydraulic resources.

The development of hydroelectric power was facilitated by significant technical advances which took place around the turn of the century. Alternating current displaced direct current as the medium for power transmission, and the development of the hydraulic speed governor made parallel generation and the development of integrated power systems possible. Protection and control technology developments improved system reliability and safety.

The installation of the first long-distance transmission line in Canada was undertaken in 1897, following the development of the electric transformer. This achievement, in which electric energy was transmitted at 11 kV for a distance of 29 km, to Trois-Rivières in Québec, was followed by a rapid expansion in the use of hydroelectric power throughout the country. By 1900, every province except Prince Edward Island and what is now Saskatchewan could boast of hydroelectric plants. These plants were modest in size, however, and only Québec, Ontario, and Nova Scotia had total capacities exceeding 10 MW. Canada's total installed hydraulic capacity at that time was 133 MW.

The mining and pulp and paper industries accounted for a major portion of the generating capacity in the early years, as exemplified by the installation of the first generator with a rating of 5.5 kW at the Laurentide Pulp Mill in Québec in 1889. Other early industrial uses of electricity were for gold dredging in the Yukon and irrigation in British Columbia.

By 1920, the total installed generating capacity in Canada had reached 2000 MW and, although a few private industries and municipalities chose to produce power for their own use, economies of scale encouraged the development of large generation, transmission, and distribution networks. In general, these networks were operated as public utilities.

By 1930, Canada's installed generating capacity had more than doubled to 4700 MW, but economic conditions reduced the construction rate in the 1935-39 period. The Second World War boosted the installation rate of new facilities in the 1940-45 period which then slowed in the late 1940's. The installation rate was again stimulated by postwar industrial expansion. Such expansion, together with rapidly growing residential and agricultural development, imposed extremely heavy demands on power generating facilities and required additions to the system. This increased installation rate could not be met from hydro resources alone. The 1950's marked the beginning of an extensive conventional thermal generating plant construction program in Canada.

By 1968, Canada's totalled installed capacity reached almost 36 000 MW, of which about 25 000 MW was hydro and about 11 000 MW thermal. For the first time, annual increments of thermal capacity nearly equalled those of hydro.

The 1960's saw the introduction of nuclear power, starting in Ontario with the first large commercial unit at Douglas Point in 1967. During the 1970's and 1980's, nuclear power installations were constructed in Ontario at Pickering (4 x 515 MW, 4 x 516 MW units; 4124 MW station) and Bruce (4 x 769 MW, 2 x 837 MW, 2 x 860 MW units; 6470 MW station), in Québec at Gentilly (1 x 638 MW unit), and in New Brunswick at Point Lepreau (1 x 635 MW unit).

These increases in the unit and station sizes for nuclear units had their counterparts in the increasing unit and station sizes for hydro and conventional thermal units. Hydro unit sizes had increased from the 9 MW units installed at Les Cèdres, Québec in 1914 to the 475 MW units installed at Churchill Falls in Labrador in 1971. Hydro station sizes had

increased from 72 MW at Les Cèdres in 1914 to 5328 MW at LG-2 in Québec in 1981. Conventional thermal unit sizes had increased from a few megawatts in the 1880's to the 574 MW units installed at Lennox, Ontario in 1976-77. Conventional thermal station sizes had increased from less than 10 MW in the early years to the 4000 MW Nanticoke station in Ontario in 1973-78.

By 1989, Canada's total installed generating capacity had grown to over 102 000 MW; an average annual growth rate since 1900 of almost 8 percent. For the period 1960-89, the corresponding average annual growth rate was 5.3 percent. Of the 1989 total electricity supply, hydroelectric plant accounted for some 57 percent of the installed capacity and some 63 percent of the generated energy. Table 1.1 shows the 1989 distribution of installed generating capacity by fuel type and province. This table clearly shows the preponderance of hydroelectric generating capacity in Newfoundland, Québec, Manitoba, and British Columbia and of thermal generation in the other provinces. This distribution of generation has had a major influence on transmission development. It should be noted that in Newfoundland most of the hydroelectric generation (Churchill Falls, 5429 MW) is located in Labrador, remote from the main provincial load centres on the Island. The bulk of the Churchill Falls output is transmitted to Québec under the terms of a contract with Hydro-Québec.

1.3 The Development of Transmission and Interconnected Systems

The growth of large generating stations in Canada has been paralleled and, indeed, made possible by the development of transmission lines of increasing voltage and capacity. These developments allowed the formation of integrated electricity networks and made the more remote hydro sites economically accessible.

Particularly in the provinces with larger electric systems, the 69 kV, 120 kV, and 230 kV voltage levels of transmission utilized in the 1930's, 1940's, and 1950's have given way to the 315 - 345 kV, 500 kV, and 735 kV alternating current levels and the ± 450 kV and ± 500 kV direct current levels of the present time. Prominent among these developments have been the 735 kV transmission lines from Manic-Outardes, Baie James, and Churchill Falls to the Québec load centres, the 500 kV transmission networks of Ontario and British Columbia, and the Nelson River high voltage direct current transmission to Winnipeg. These developments took place in the 1960's and 1970's and raised the transfer capacity of transmission lines from hundreds to thousands of megawatts.

Concurrent with the integration of provincial power systems has been the development of international and interprovincial transmission interconnections. These ties have been made to achieve anticipated benefits which may include cost savings due to lower installed reserve requirements, the ability to install larger, more economical generating units, lower operating reserve requirements, seasonal diversity and economy energy exchanges, and the ability to conclude firm power contracts. Other anticipated benefits included increased service reliability and emergency assistance.

Due to geographic circumstances, and in some cases, seasonal peak diversity, it has tended to be more advantageous for Canadian utilities to establish international rather than interprovincial interconnections. Nevertheless, interprovincial interconnections have been established as and when judged to be economical by the electric utilities.

Table 1.2 presents a chronology of the major regional interconnections. Currently, there are 33 large interprovincial ties, with a total design capability of some 10 000 MW. There are also two 230 kV interconnections between Western and Eastern Ontario. As shown in Table 1.2, the first interconnection at 230 kV was built between Québec and Ontario in 1928, followed by ten other 230 kV and 115 kV interconnections between Québec and Ontario load centres in the period up to 1966. In 1956 a 115 kV interconnection was made between Manitoba and the Western Ontario system. Additional ties between Manitoba and Western Ontario were placed in service at 230 kV in 1972 and 1973. Meanwhile, 230 kV ties were established between the Western and Eastern Ontario systems in 1969 and 1972. Commencing in 1961, New Brunswick and Nova Scotia were interconnected by a 138 kV transmission line, followed by a second similar interconnection in 1965. Subsequently, a 345 kV interconnection was built in 1976. Ties between Québec and New Brunswick load centres were made starting with a 69 kV transmission line in 1965. This was followed by a direct current tie and a 230 kV transmission line in 1972, and a further direct current tie and a 345 kV transmission line in 1985. To deliver power from the Churchill Falls development, three 735 kV transmission lines were commissioned between Churchill Falls and the Hydro-Québec system in 1971, 1972, and 1973, respectively. Manitoba and Saskatchewan were linked by a 138 kV line in 1960, upgraded to 230 kV in 1968, a second 230 kV transmission line in 1972 followed by a third 230 kV line in 1979. There are also two 115 kV interconnections between Manitoba and Saskatchewan. Alberta - British Columbia transmission interconnections were established in 1973 at 138 kV and in 1985 at 500 kV.

In 1977 New Brunswick and Prince Edward Island were interconnected via two 138 kV submarine cables. The final link between the mainland power systems in Canada was placed in service in 1989, when a 230kV transmission line from Saskatchewan was connected to a 138kV transmission line from Alberta via a direct current converter/inverter.

There are now over 100 international transmission lines in place to provide for Canada's electricity trade with the United States, including 36 bulk power interties rated at 69 kV or higher, with a total power transfer capability of 13 500 MW.

The technical developments in generation and transmission, and their attendant economies of scale, have led over the years to groupings of interconnected generation, transmission, and distribution systems, and eventually to interconnected interprovincial and international systems. In the early years, these systems were privately or municipally owned. Because of the growing importance of electricity and the conviction in many jurisdictions that it could be provided at lower cost under public ownership, most systems eventually became provincially-owned utilities. Ontario Hydro became the first such entity in 1906, although this did not prevent the subsequent issuance of licences to develop hydro power to a number of pulp and paper companies in Ontario.

As early as 1910, Québec created the Québec Streams Commission to regulate dam construction and operation, and the production of power. However, all of the power facilities remained in private hands until the creation of Hydro-Québec in 1944, when the facilities of the Montreal Light, Heat, and Power Company were acquired. In 1963, Québec acquired the remaining private utilities. One year earlier, in 1962, B.C. Hydro had consolidated public ownership, which had started in the 1940's, by taking over the facilities of the B.C. Electric Company.

Following the First World War, New Brunswick, Manitoba and Nova Scotia took the path of Ontario and established agencies to produce and distribute electric power. In 1918, the New Brunswick Electric Power Commission (NBEPC) was created, and in the following year, the Manitoba Power Commission and the Nova Scotia Power Commission were established. Since its inception the NBEPC has been the principal utility in New Brunswick, but both Manitoba and Nova Scotia began by sharing these duties between public and private utilities. However, the private utilities in Manitoba and Nova Scotia were later integrated into the provincially-owned systems. The Government

of Nova Scotia has just sold all its shares in the Nova Scotia Power Corporation to private investors.

As in Ontario, Saskatchewan's electrical industry has had a history of public ownership. The Saskatchewan Power Corporation dates back to the formation of its predecessor, the Saskatchewan Power Commission, in 1929. The initial activities of the Commission were concerned with the purchase of a number of municipally-owned generating plants that were the province's main source of power. Since that time, the Saskatchewan Power Corporation has been the province's principal producer.

In order to encourage the development of the resources of northern Canada, the federal government established the Northern Canada Power Commission (NCPC) in 1948 to construct and operate electric facilities in the north. The Commission met that challenge by constructing both hydro-electric and thermal-electric generating facilities. The NCPC was superseded by the establishment of the Yukon Energy Corporation in 1987, and by the formation of the Northwest Territories Power Corporation in 1988.

Investor-owned electrical utilities have been pre-eminent throughout the development of the industry in Alberta, Prince Edward Island and Newfoundland; in addition, municipally-owned electric utilities have long been active in Alberta and Prince Edward Island. The provincially-owned Newfoundland and Labrador Power Commission (now known as Newfoundland and Labrador Hydro) has played a growing role in the expansion of electrical facilities in Newfoundland.

There are still many industry-owned generating stations being operated in the mining, and pulp and paper industries. The largest industrial establishment producing its own energy in Canada is the Aluminum Company of Canada Limited (Alcan) which operates a total of 2827 MW of hydro-electric capacity in six developments in British Columbia and Québec.

1.4 The Existing Industry Structure

Under the Constitution Act, electricity generation, transmission and distribution is primarily within the jurisdiction of the provinces. As a consequence, Canada's electricity supply industry is organized along provincial lines. In most provinces, the industry is vertically integrated, with the bulk of the generation, transmission, and distribution being

provided by a few principal utilities. Although some of these utilities are privately owned, most are Crown corporations owned by the provinces. The major utilities are listed in Table 1.3.

In 1989, among the major electric utilities, eight were provincially-owned, two were territorially-owned, five were investor-owned, and two were municipally-owned. In 1989, provincial electric utilities owned approximately 82.5 percent of Canada's total installed generating capacity and produced about 82 percent of total generated electricity. The five investor-owned utilities accounted for 5.8 percent of Canadian electric utility capacity and produced approximately 7.3 percent of total generated electricity. Municipal utilities accounted for 1.6 percent of capacity ownership, and produced 0.8 percent of total generated electricity. The two territorial Crown corporations accounted for 0.3 percent and 0.2 percent of capacity and generated electricity, respectively.

In addition to the 17 major electric utilities, listed in Table 1.3, there are about 60 large industrial establishments generating electricity mainly for their own use. A few also sell energy to municipal distribution systems or utilities. These industries are concentrated in the pulp and paper, mining, and aluminum smelting sectors. In 1989, industrial establishments owned about 6.0 percent of total capacity and produced approximately 8.0 percent of total generated electricity in Canada. Since 1970, the shares of capacity and production by industrial establishments have fallen by half.

As well as the major electric utilities and industrial establishments, there are about 364 smaller utilities most of which are located in Ontario. Some of these are owned by investors, but most are owned by municipalities. Most do not own generating capacity, and purchase power from the major utility in their province. In 1989, the smaller utilities accounted for 3.8 percent of total capacity, and produced 1.7 percent of electrical energy.

From the above discussion, it is evident that the existing structure of the Canadian electricity supply industry is dominated by vertically-integrated, provincially-owned utilities. In general, these utilities operate as provincially-regulated monopolies with respect to all aspects of electricity supply, including generation, transmission, and distribution, and with the mandate of providing reliable supplies of electricity at least cost. In 1983, Hydro-Québec's mandate was modified to facilitate electricity exports.

Because of the preponderantly provincial emphasis, the electricity supply systems have been constrained by provincial boundaries and interests. To some extent, their size and structure have been determined by political and constitutional realities and local economic forces. These factors have also influenced the character, extent, and timing of interprovincial and international interconnections.

1.5 The Nature of Interprovincial Cooperation

The motivation for construction of interprovincial interconnections is the same as that which has led to the interconnection of intraprovincial systems, and has derived from the desire to realize the benefits previously noted.

Typically, an interconnection agreement between two utilities will remain in force for an extended period of time (e.g. 30 years) and will provide for mutual assistance during emergencies, improve the reliability of bulk power supply through coordinated operations, achieve operating economies through the exchange of surplus power and energy, and, to the extent deemed mutually desirable, secure additional economies through coordinated development. An agreement will define the various types of capacity and energy to be traded, the planning and operating reserves to be maintained, as well as the ownership, operation, and maintenance of the interconnecting facilities. This type of agreement falls short of complete integration of the planning and operating functions, and shared ownership of major facilities (e.g. as envisaged in the Maritime Energy Corporation concept - see Section 3.2.3).

Until recently, the provinces have generally preferred to construct their own generating facilities rather than enter into long-term purchases of firm power and energy from other provinces. They have been unwilling to sacrifice any significant degree of autonomy or to forgo the short-run income and employment benefits associated with in-province construction of facilities, despite the prospect of long-run net economic benefits. Exceptions to this general statement are Maritime Electric's 10 percent ownership participation in the 200 MW Dalhousie No. 2 unit in New Brunswick, Hydro-Québec's purchase of most of the Churchill Falls output, and Manitoba Hydro's power sales to Ontario Hydro in the early to mid-1970's. These examples were motivated by the favourable economics compared to in-province alternatives.

There is now evidence that the attitude of at least some of the provinces toward purchases of firm power and energy is changing. For example:

- a) In October 1987, Ontario Hydro and Manitoba Hydro announced the purchase by Ontario Hydro of 200 MW of firm power for a five-year period commencing November 1, 1998.
- b) In December 1989, Ontario Hydro and Manitoba Hydro entered into a contract for the sale of up to 1000 MW of firm power to Ontario Hydro for a 22-year period commencing November 1, 2000.
- c) In 1991, Hydro-Québec began purchasing firm peaking power from New Brunswick Power.
- d) Maritime Electric has entered into a three-year unit participation agreement with NB Power for 20 MW of Point Lepreau #1. This agreement has received the approval of the PEI Public Utility Commission.
- e) Maritime Electric is now negotiating unit participation agreements with NB Power and NSPC for ownership shares of Belledune #2 and Point Aconi #1 respectively for the lives of these units.
- f) Newfoundland and Labrador Hydro and Hydro-Québec are negotiating the long-term sale to Hydro-Quebec of output from the Gull Island and Muskrat Falls hydroelectric sites to be developed on the Lower Churchill River in Labrador.

In addition to the above, the provinces of British Columbia, Alberta, Saskatchewan, and Manitoba and their electric utilities are pursuing studies aimed at realizing the potential benefits discussed in the May, 1990 preliminary report of the Western Electric Utility Cooperation Group and in the 1989 B.C.-Alberta coordination study. The latter study estimated potential benefits ranging from \$600 million to \$1200 million in present worth 1988\$ for the period 1990 to 2010, depending on the degree of coordination.

ENDNOTES

In preparing this chapter, extensive use was made of material from the following:

- Various issues of "Electric Power in Canada" by Energy, Mines and Resources Canada.
- "The Structure of the Canadian Electricity Supply Industry" an internal document of Energy, Mines and Resources Canada.
- "Interprovincial Cooperation in Electric Systems Development" an internal document of Energy, Mines and Resources Canada.

Table 1.1 Installed Generating Capacity by Fuel Type and Province, 1989

	Hydro	Coal	Nuclear	Oil	Natural Gas	Other	Total
				(MW)			
Nfld.	6 660	0	0	799	0	0	7 459
P.E.I.	0	20 ¹	0	122	0	0	142
N.S.	386	1 162	0	594	0	19	2 161
N.B.	903	298	680	1 578	0	62	3 521
Que.	26 530	0	685	1 337	8	5	28 565
Ont.	7 849	10 581	11 238	2 527	449	64	32 708
Man.	3 641	389	0	3	4	23	4 060
Sask.	836	1 531	0	24	433	22	2 846
Alta.	734	5 267	0	15	1 577	336	7 929
B.C.	10 849	0	0	244	1 032	374	12 499
Yukon	82	0	0	46	0	0	128
N.W.T.	53	0	0	124	20	0	197
Canada	58 523	19 248	12 603	7 413	3 523	905	102 215

Source: Electric Power Statistics, Volume II, Statistics Canada, Catalogue 57-204.
Energy, Mines and Resources Canada.

Note: ¹ 20 MW joint ownership of
Dalhousie G.S. in N. Brunswick

Table 1.2

Chronology of Regional Interconnections

Interconnection	Voltage (kV)	Date -in-service
Québec-Ontario	230	1928
Québec-Ontario	115	1930 ¹
Québec-Ontario	230	1932
Québec-Ontario	115	1933 ¹
Québec-Ontario	115	1940 ¹
Québec-Ontario	230	1941
Québec-Ontario	115	1942
Québec-Ontario	115	1949
Québec-Ontario	115	1949
Manitoba-Ontario	115	1956 ²
Manitoba-Saskatchewan	230	1960
New Brunswick-Nova Scotia	138	1961
New Brunswick-Nova Scotia	138	1965
Québec-New Brunswick	69	1965
Québec-Ontario	115	1966
Québec-Ontario	115	1966
Western Ontario-Eastern Ontario	230	1969
Labrador-Québec	735	1971
Labrador-Québec	735	1972
Western Ontario-Eastern Ontario	230	1972
Manitoba-Saskatchewan	230	1972
Manitoba-Ontario	230	1972
Québec-New Brunswick	±80 (DC)	1972
Québec-New Brunswick	230	1972
Manitoba-Ontario	230	1973
Labrador-Québec	735	1973
Alberta-British Columbia	138	1973
New Brunswick-Nova Scotia	345	1976 ³
New Brunswick - Prince Edward Island	138	1977 ⁴
New Brunswick - Prince Edward Island	138	1977 ⁴
Manitoba-Saskatchewan	230	1979
Alberta-British Columbia	500	1985
Québec-New Brunswick	±80 (DC)	1985
Québec-New Brunswick	345	1985
Saskatchewan-Alberta	230	1989

- ¹ 230 kV constructions.
² Constructed in 1931; interconnected in 1956
³ Operated at 138 kV until 1979.
⁴ Submarine cable.

interconnections are alternating current (AC), except for the Québec-New Brunswick direct current (DC) facilities.

Québec-Ontario interconnections and all Québec-New Brunswick AC interconnections are radial (i.e. between one system and an isolated section of the other system).

Table 1.3

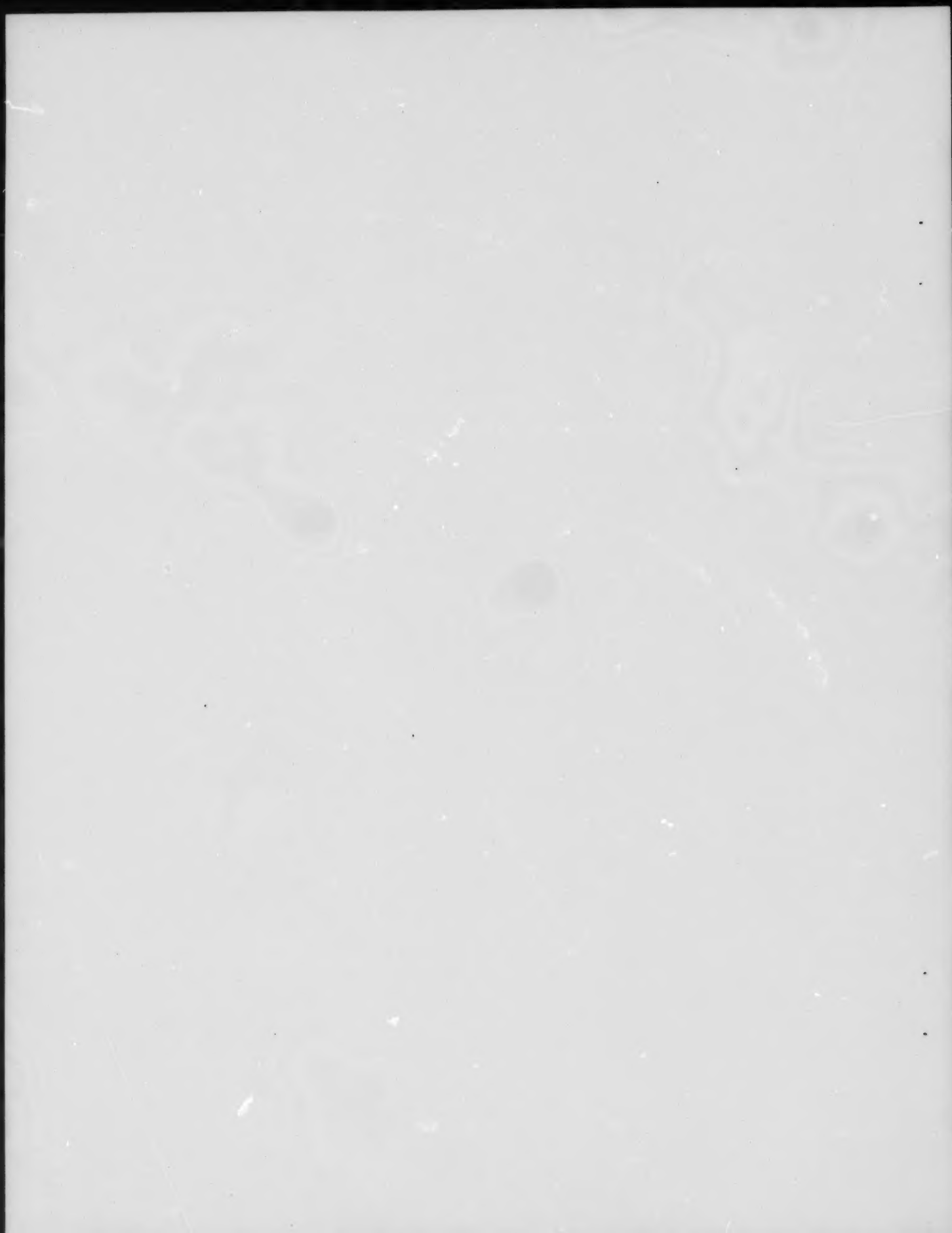
Major Electric Utilities by Province

Province	Utility	Ownership
Yukon	Yukon Energy Corporation	Territorial
Northwest Territories	Northwest Territories Power Corporation	Territorial
British Columbia	British Columbia Hydro and Power Authority	Provincial
	West Kootenay Power	Investor
Alberta	Alberta Power Ltd.	Investor
	Edmonton Power	Municipal
	TransAlta Utilities Corporation	Investor
Saskatchewan	Saskatchewan Power Corporation	Provincial
Manitoba	The Manitoba Hydro-Electric Board	Provincial
	City of Winnipeg Hydro-Electric System	Municipal
Ontario	Ontario Hydro	Provincial
Québec	Hydro-Québec	Provincial
Nova Scotia	Nova Scotia Power Corporation	Provincial ¹
Prince Edward Island	Maritime Electric Co. Ltd.	Investor
New Brunswick	New Brunswick Electric Power Commission	Provincial
Newfoundland	Newfoundland and Labrador Hydro	Provincial
	Newfoundland Light & Power Co. Ltd.	Investor

Source: Energy, Mines and Resources Canada.

Note:

¹ Nova Scotia Power was privatized in 1992.



2. NATIONAL ELECTRICITY PLANNING INITIATIVES



2. NATIONAL ELECTRICITY PLANNING INITIATIVES

2.1 Introduction

This chapter examines past attempts to promote the concept of a 'national grid' interconnecting the provincial electric utilities from coast to coast. Separate sections discuss the two major proposals for a national grid that have been advanced over the past thirty years. Also outlined are the difficulties encountered in promoting a national body to operate such a grid.

2.2 The Vision of a National Electricity Grid

The idea that Canada should have a single national electricity grid first received modern political expression in a speech given by Prime Minister John Diefenbaker at Kitimat, British Columbia, on 24 August 1959. Mr. Diefenbaker introduced the subject by talking about the possibility of an electric power pool in the Maritimes and about the interchanges of power that were then taking place between Ontario and Québec, between Ontario and Manitoba, and between Manitoba and Saskatchewan. He then went on to say: "I can visualize a National Energy Grid anchored at one end on the Hamilton River in Newfoundland and at the other by the Columbia and the Taku."¹ The Prime Minister recognized that technical problems associated with the long-distance transmission of electric power stood in the way of this vision, but he was confident that these could be overcome. "I can visualize", he said, "large blocks of inexpensive power being 'bumped' and 'wheeled' from surplus areas to deficit areas across this land."²

In July 1960, the Minister of Northern Affairs and Natural Resources expanded on the Prime Minister's idea. He called for a trans-Canada electricity grid that would serve to distribute power across the country and also provide the basis for the development of the "great reserves of power in the remote areas in our north".³

Mr. Diefenbaker and the Minister were not the only ones enthused by the imagery of a vast trans-provincial electricity network. The General Manager of the Saskatchewan

¹Notes for a Speech by the Prime Minister, the Rt. Honourable John G. Diefenbaker, to the Associated Boards of Central B.C. at Kitimat, August 24 1959, p.18.

²Ibid.

³HOUSE OF COMMONS DEBATES - OFFICIAL REPORT, Third Session, Twenty-Fourth Parliament, July 27, 1960, p.7040.

Power Corporation argued that such a grid would provide significant benefits to all concerned. The General Manager of the New Brunswick Electric Power Commission echoed this view, stating that a stronger national grid was the "shape of things to come".⁴ The Chairman of the Ontario Hydro Electric Power Commission called for a major study to assess the most efficient course for Canadian power development over the next forty years. In addition, the Chairman of the Manitoba Power Commission called for a DC transmission system anchored at one end in the Yukon and extending in a great arc through the Nelson River basin in Manitoba all the way to an eastern anchor in Labrador.

By 1962 there was enough momentum behind the idea to cause Mr. Diefenbaker to take concrete action. In the Speech from the Throne read in the House of Commons in January 1962, the government indicated that the provinces had been invited to meet with the federal government in order to discuss the steps that might be taken to establish long-distance power transmission facilities capable of linking provinces and eventually all of the different regions of Canada.⁵ In his letters to the provincial premiers, Mr. Diefenbaker explained that the purpose of the conference would be to assess the advantages of interregional interconnections, to discuss ways of solving the problems associated with long-distance transmission, and to define the roles that the two levels of government could play in the planning and research needed to bring about such a development.⁶

The federal government's proposal was widely applauded. However, a few notes of censure could also be heard. In reply to the Speech from the Throne, the opposition pointed out that not all provinces would welcome federal involvement in what was essentially a provincial matter.⁷ In fact, both Québec and Newfoundland expressed their reservations about this proposal. Mr. Diefenbaker himself was sensitive to the constitutional problems entailed by his proposal. He subsequently stated that "the federal government intends as always to respect the jurisdiction and prerogatives of provincial governments".⁸ However, he also pointed out that interprovincial power developments were of direct interest to the federal government; evidently, he thought that federal

⁴R.E. Tweeddale, *Shape of Things to Come in Electric Power* in THE MONETARY TIMES, July 1962, p.16.

⁵HOUSE OF COMMONS DEBATES - OFFICIAL REPORT, Fifth Session, Twenty-Fourth Parliament, January 18, 1962, p.2.

⁶Notes for opening remarks by the Rt. Honourable John G. Diefenbaker, Prime Minister, at the Federal-Provincial Conference on Long-Distance Transmission, Ottawa, March 19, 1962, p.8.

⁷HOUSE OF COMMONS DEBATES - OFFICIAL REPORT, Fifth Session, Twenty-Fourth Parliament, January 25, 1962, pp.188-89.

⁸Notes for opening remarks by the Rt. Honourable John G. Diefenbaker, Prime Minister, at the Federal-Provincial Conference on Long-Distance Transmission, Ottawa, March 19, 1962, p.7.

initiative in respect of national power planning was needed. Most of the provinces, whether or not they agreed with the idea, were prepared to respond.

The Federal-Provincial Conference on Long Distance Power Transmission was held in Ottawa on 19 March 1962. In his opening remarks to the conference, Mr. Diefenbaker explained why he thought the initiative was necessary. To begin with, he asserted that the long-distance transmission of electrical energy would yield great benefits to the participating provinces. Second, he saw a national electricity grid as the equivalent of the transcontinental railways, the trans-Canada highway, the nation-wide civil aviation system, and the cross-Canada radio and television networks. All of these, he said, "are links helping to bind this country together".⁹ Finally, he noted that if northern hydroelectric resources were going to be developed, they would have to be connected to southern markets.

One paragraph of Mr. Diefenbaker's remarks is perhaps worth noting in full, because it demonstrates that his vision of a national grid was combined with a certain practical realism:

The federal government recognizes that a nation-wide grid will not suddenly leap into being. The establishment of electrical transmission facilities...should take place at the time and in the sequence of development that will serve the country best. To install any particular link before a market existed for the power or when the power could not be delivered at an economic unit cost, would obviously be unrealistic and futile. It would be equally unsound to make plans for regional systems without taking fully into account the possibility and desirability of interregional connections. Interconnections should be designed and planned to be compatible with that objective.¹⁰

2.3 The National Power Network Study

The participants at the Federal-Provincial Conference agreed to establish a working committee responsible for organizing a National Power Network Study, and this committee quickly came to the conclusion that a two-stage approach was needed. The first would define the backbone of a trans-Canada electrical interconnection, assess its

⁹Ibid., p.2.

¹⁰Ibid., p.5.

probable benefits and costs, and recommend any further studies that might be required. The second would then carry out the detailed technical and economic studies recommended in Stage I. The ultimate objectives were: (i) to establish the feasibility of an integrated national power network; and (ii) to establish a factual basis for the formulation of national power network integration policy.¹¹

Stage I was carried out by H.G. Acres and Company. It examined the merits of a coast-to-coast high voltage transmission line, which would proceed along a generally southern route from Halifax to Vancouver, in close proximity to Canada's major load centres. Variants of this main route indicated how the hydroelectric resources in Labrador and on the Peace River could be brought within the scope of the national plan. Insofar as the hydro resources on the Nelson River were concerned, it was assumed that they would be connected to the main line by an intertie extending around the west side of Lake Winnipeg. The study concluded that such a project would indeed facilitate the development of Canada's remote hydroelectric resources, and that it would yield substantial benefits to the national and provincial economies. It concluded by recommending strongly that a Stage II assessment proceed.

This recommendation was accepted by federal and provincial ministers, and in October 1964 the consulting firm of T. Ingledow and Associates was selected to undertake the Stage II assessment. The firm's final report, in six volumes, was completed in February 1967. The plan it proposed called for the development of hydroelectric sites in Québec, British Columbia, and Manitoba, and the deferral of construction of coal-fired generating stations on the Prairies and in the Maritimes. It was assumed that large nuclear facilities would become the preferred choice for electricity generation once the economic hydro sites were all developed. The necessary facilities were all to be put in place incrementally, as natural extensions of the existing provincial transmission networks. Finally, the plan assumed that there would be an extensive increase in electricity exports from Manitoba, but no major increases elsewhere.

The principal conclusions of the Stage II study were that interconnections and coordinated interprovincial power systems development would yield significant economic benefits, that a national network would increase the reliability of the participating systems, and that some form of central authority would be needed to

¹¹H.G. Acres and Company, NATIONAL POWER NETWORK STAGE I ASSESSMENT, January 1964, p.ii.

coordinate planning, development, and operations. With regard to the last finding, the study noted that "inasmuch as the power industry in Canada is presently organized principally on a provincial basis with limited inter-provincial coordination between systems, this requirement may be considered to have important implications for the operation of the industry in the future if the benefits of system coordination on a national scale are to be realized".¹²

The report recommended that further studies be undertaken to define the administrative arrangements that would be needed to construct and operate a national system of interconnections, to plan the development of the necessary facilities, and to establish the technical feasibility of the proposed interconnections. Despite these recommendations, the Federal-Provincial Working Committee decided against a major new national grid initiative. One reason was the large number of assumptions upon which the study had been based. The large range of uncertainty associated with each assumption cast doubt upon the conclusions. Another was the capital-intensive nature of the projects being proposed, which made the scheme as a whole financially risky. A third reason was the prospect of major new north-south interties with the United States, which to some Canadian utilities appeared to be a more attractive option than east-west interconnection of the Canadian systems. Finally, the recommendations made by T. Ingledow and Associates were partially superseded by events: hydroelectric projects on the Nelson River in Manitoba and the Churchill River (formally the Hamilton River) in Labrador were already moving forward as independent initiatives, thus depriving the national grid concept of part of its original impetus.

As the Stage II assessment had advanced, the original terms of reference had been expanded to include consideration of regional electricity networks. These were thought of as possible intermediate stages between independent provincial systems and a full-scale national grid, and they were shown to have many of the advantages of the latter without some of the disadvantages. In light of these considerations and the ones noted in the paragraph above, the Committee concluded that future attention should be focussed on the development of regional ties rather than a trans-Canada electrical network.

¹²T. Ingledow & Associates Limited, NATIONAL POWER NETWORK STAGE II ASSESSMENT, vol. I, p.25.

2.4 The Provinces Take the Initiative

Although the Canadian interconnected systems continued to grow almost independently throughout the 1960's and early 1970's, the idea of a national grid was not one that was about to go away. In a paper delivered in October, 1972, the Chairman of the B.C. Hydro and Power Authority stated that regional interconnections were useless for purposes of sharing major generating units or interchanging energy on a significant scale. He called for a true national grid, as opposed to isolated electrical regions with only token ties between them.¹³ This idea was seconded by the engineering firm Leighton & Kidd Limited, which submitted a brief in March of 1973 to the federal government calling for a re-evaluation of the national grid concept.¹⁴

The federal government was lukewarm to these ideas. On 23 January, 1974, it announced at the First Ministers Conference on Energy that the policy of the Government of Canada would be to strengthen regional interconnections, as the 1967 study had suggested. To facilitate the expansion of regional ties, the federal government was prepared to: (i) share up to 50% of the cost of interconnection studies; and (ii) in cases where the resources of the provinces and/or utilities were inadequate, finance up to 50% of the capital costs of approved projects by providing loans at Crown corporation rates. A "regional interconnection" for purposes of this policy was defined to mean any connection between two or more provinces, or any connection between distinguishable regional portions of power systems within a province.

At the January 1974 meeting where the federal government announced this policy, several of the provinces indicated that they were thinking along quite different lines. In their opening statements, the Premiers of Newfoundland, Nova Scotia, Prince Edward Island, and Manitoba all endorsed the notion of a national electricity grid. Typical of their statements was the statement of the Premier of Newfoundland: "This grid would permit early development of renewable hydro resources and permit the free movement of this form of energy to any area of the country requiring such energy."¹⁵ The next day, British Columbia, Alberta, Saskatchewan, Ontario and New Brunswick gave their support to the idea. The federal government responded by saying that any national grid

¹³David Cass-Beggs, *Energy in Transition*, ENGINEERING JOURNAL, February 1973.

¹⁴Leighton & Kidd Limited, A NATIONAL ELECTRIC POWER POLICY FOR CANADA, March 1973.

¹⁵1974 Federal - Provincial First Minister's Conference on Energy, VERBATIM REPORT, Canadian Intergovernmental Conference Secretariat, p. 125.

initiative would have to come from the provinces. Until such time as the provinces considered that a national grid was feasible, the federal government would confine its support to the expansion of regional interties. This basic approach was described in a letter to the provinces a week later. The provinces were each invited to comment in detail on the national grid proposal, and asked how the subject might best be dealt with.¹⁶

By the following August, all of the provinces had responded, and most were positive. The Premier of British Columbia called for an immediate study of the topic by those provinces that might be interested. He proposed a linking of Canada's eastern and western transmission systems by a 750 mile line from the Nelson River in Manitoba to James Bay in Québec. He also thought that a similar link between the Peace and Nelson rivers might prove feasible. However, Québec's Minister of Natural Resources expressed doubts about the idea of a comprehensive national electricity system, for both economic and electrical reliability reasons. Smaller scale bilateral expansions of the interconnected system, the Québec minister felt, were another matter; both interprovincial and international interconnections had already been shown to yield significant economic advantages.¹⁷

Despite certain reservations, there was enough provincial support for the national grid concept to sustain a new initiative. On April 17, 1976, the Interprovincial Advisory Council on Energy (IPACE - an independent advisory body composed of provincial government officials to consider energy issues) agreed to go ahead with a new study. The federal government was invited to participate and to contribute funding; however, this invitation was later withdrawn. The provinces agreed to grant the federal government observer status only.

2.5 The IPACE Study

In the fall of 1977 a study group was formed under the Supervisory Committee of IPACE. The study group's mandate was to evaluate and compare the benefits to be gained from normal system expansion with those that could be obtained through the pooled expansion of combined power systems.

¹⁶See EMR file 6760-0, vol.1.

¹⁷See EMR file 6760-0, vol.2.

The study group developed a "conceptual plan" which in essence was a massive new east-west transmission system extending from Selkirk in British Columbia to Eel River in New Brunswick. It was anticipated that in the absence of this initiative the provincial utilities would augment interprovincial transfer capacity by 4800 MW during the 1980-2000 period. The conceptual plan proposed an additional increase in transfer capacity of some 7520 MW, consisting of: (i) an additional 200 MW between B.C. and Alberta; (ii) two new HVDC links of 1000 MW each between Alberta and Manitoba; (iii) two new HVDC links of 1500 MW each between Winnipeg and Sudbury; (iv) an additional HVDC circuit of 2000 MW between Ontario and Québec; and (v) an additional 320 MW HVDC between Québec and New Brunswick. The conceptual plan did not propose any increases of transfer capacity between Canada and the United States.

Two principal benefits were expected to derive from the expanded national grid. The first was an operational benefit; it was assumed that the interconnections would provide opportunities to replace expensive oil-fired generation with less costly hydro generation. This assumption gained prominence because of the oil-price shocks of the 1970's. The second was a reserve benefit; it was assumed that generating reserves could be reduced by approximately 5 percent, because of time-diversity in provincial peak demands and because of the reserve sharing implicit in the expanded interconnections. The study noted several other benefits deriving from the conceptual plan such as earlier development of hydroelectric resources, enhanced security of supply, and increased flexibility in responding to changing energy policies and external circumstances, but no attempt was made to quantify these.

The estimated net benefits of the plan were very sensitive to assumptions regarding future fuel prices. With no real escalation in fuel prices net benefits were negative. With 2 percent per annum escalation, net benefits were modestly positive. At higher rates of escalation net benefits were significantly positive. The authors of the study summarized their conclusions this way: "The reduced expenditures on generating capacity and fuel offset the costs of the strengthened interprovincial interconnections, and a modest net economic advantage is indicated under the conceptual plan, particularly if fuel prices continue to rise relative to other costs."¹⁸

¹⁸IPACE Networks Study Group, AN EVALUATION OF STRENGTHENED INTERPROVINCIAL INTERCONNECTIONS OF ELECTRIC POWER SYSTEMS, October 1978, vol.I, p.4.

In addition to the cost-benefit analysis of the proposed conceptual plan, the IPACE study is interesting because it tried to come to grips with several of the other problems that arise in considering the merits of a national grid. Three of these in particular are worth noting: the question of whether enhanced north-south electricity trade would be better for Canada than enhanced east-west trade; the issue of which level of government would have jurisdiction over a national grid; and the question of how a system of strengthened interprovincial interconnections would be organized.

With regard to the issue of whether north-south trade is better than east-west trade, the study pointed out that the two are not necessarily mutually exclusive, and that interprovincial interconnections, in general, increase access to export markets. Ideally, an interprovincial pool would be operated so as to maximize collective benefits to Canada as a whole. However, it was recognized that this would create a problem; how would the resulting benefits then be shared among provinces? The study did not try to address this question. It simply noted that compromises would be needed to ensure that all provinces were net beneficiaries.

The jurisdictional issues raised by the concept of an interprovincial electricity network were ones that IPACE took very seriously, and Professor Leo Barry, who was then at Dalhousie Law School, was asked to provide an opinion on the matter. In order to put the constitutional issues in sharpest relief, Professor Barry was asked to consider the concept of an interprovincial network assigned extensive powers and duties by the provinces.¹⁹ The specific question to which he was asked to respond was the following: "Can matters be arranged so that the federal government never has the opportunity, whether it seeks this or not, of becoming involved in the planning, construction, and operation of the network?"²⁰ Professor Barry's answer: "There is no way in which the provincial governments can obtain absolute assurance that the federal government will never become involved in the development and administration of an interprovincial electricity network."²¹ His study goes on to note, however, that political factors may prevent the federal government from exercising its jurisdiction. If the network were to be developed in a spirit of cooperation with the federal government, jurisdictional uncertainty could be avoided by having it operate with authority delegated from both

¹⁹Ibid., vol.II, p.112.

²⁰Ibid., vol.II, Appendix I, p.1

²¹Ibid., vol.II, Appendix I, p.1.

levels of government.²² On the other hand, the likelihood that the federal Parliament could exercise jurisdiction would increase with the degree of integration and interdependence. This suggests that the provinces, if they wish to minimize the possibility of federal involvement, should separate ownership of the interprovincial facilities (owned by the provinces) from those needed for normal intraprovincial development (owned by the utilities).²³

The study decided that "a government agency, to plan and implement a coast-to-coast network, does not appear necessary".²⁴ Instead, it proposed the creation of an all-provincial institution, an Interprovincial Power Coordinating Council (IPCC), to promote interconnections and pooling. The idea was that this would be a voluntary organization which in time might evolve into a more structured entity responsible for financing, constructing, and operating strengthened interprovincial interconnections, subject to provincial approvals. It was understood that each province would continue to plan and execute its own generation development programs. However, the IPCC would review such plans to identify opportunities where economies might be realized on a regional basis. It would also be responsible for coordinating the operation of the installed capacity of the cooperating utilities so as to minimize costs and maintain system-wide reliability. The pool agreement would also specify reserve levels and indicate how these would be used in the event of emergencies.

The study pointedly noted that "the future stream of benefits over the life of the strengthened interprovincial interconnections is most uncertain...[and] in certain cases, there is no direct relationship between the locations of the assets required and the locations where the benefits are realized".²⁵ For these reasons, it was suggested that the enhanced system of interconnections be financed by governments rather than utilities. The question of how the benefits and costs would be allocated among provinces was not addressed. It was simply assumed that any net benefits would be shared "equitably among the participants".²⁶

The study concluded on an optimistic note. While not trying to understate the difficulties involved, the authors pointed to the Canadian electricity industry's long record of

id., vol.II, Appendix I, pp.8-9.

id., vol.II, Appendix I, p.44.

id., vol.I, p.5.

id., vol.I, p.6.

id., vol.I, p.6.

achievement, and concluded that "satisfactory arrangements for the establishment of a network of strengthened interprovincial interconnections can be made provided that all parties have a desire to find a mutually satisfactory solution and are willing to extend their cooperation to that end".²⁷

However, in a press release issued on 12 December 1978, IPACE concluded that the net benefits of strengthened interconnections did not justify their installation, at least at that time. The Committee did acknowledge that some additional links between adjoining provinces might prove to be economic, and noted that further studies were underway in the four western provinces and in the Atlantic region. IPACE announced its intention to follow these developments closely.²⁸

2.6 Conclusions

Despite the very considerable efforts of both the provinces and the federal government in the decades of the 1960's and 1970's, nothing even approximating a national electricity grid has ever come about.

Both of the national grid proposals studied in the past have been defined as large east-west transmission schemes, requiring large expenditures of capital. While both were shown, under certain assumptions, to provide some net economic benefits, neither one was so favourable as to demand immediate development. The economic benefits were not great enough to cause decision makers to go ahead; the ultimate conclusion in both cases was to favour more modest regional initiatives.

The weakness of the economic case in favour of a national grid was compounded by the fact that there was no obvious institutional mechanism whereby a trans-Canada electricity network could be brought into being. The IPACE study identified this shortcoming and put forward the concept of an Interprovincial Power Coordinating Council (IPCC) that respected constitutional norms, that could have evolved gradually, and that would have probably done much to enhance interprovincial cooperation. However, the recommendation that an IPCC be implemented was never acted upon, which suggests

²⁷Ibid., vol.I, p.7.

²⁸News Release, IPACE REPORT EVALUATES FEASIBILITY OF IMPROVED ELECTRICAL INTER-CONNECTIONS BETWEEN PROVINCES, December 12, 1978. See EMR file 1135-J35, volume 4.

that the fundamental constraints against interprovincial cooperation perhaps lie elsewhere.

These constraints may be imbedded within the constitutional structure of the country as a whole. For a 'national grid' to become a reality, the provinces would have to delegate at least some authority to an extraprovincial body. There would be reluctance to take this course, and decision making could become difficult if the provinces wished to retain a right of veto over national grid projects. There would have to be a federal-provincial agreement of some kind, and jurisdictional ambiguity might cause problems in the resolution of disputes.

Barring these jurisdictional and institutional problems, other issues would have to be resolved in order for a 'national grid' to exist. These issues include the proposed sharing of the costs and benefits, coordination of international trade, the type and location of new generating facilities, etc. An extraprovincial electricity agency would have to settle all of these issues before a 'national grid' could become a reality.

The historical evidence points to a single conclusion: a 'national grid' - defined as an entity somehow separate from and transcending the several provincial grids - has not been an idea that has borne much fruit. In the two cases on record, governments rejected a national scheme in favour of expanding regional cooperation. How well this has worked is explored in Chapter 3.

3. EXPERIMENTS IN REGIONAL PLANNING



3. EXPERIMENTS IN REGIONAL PLANNING

3.1 Introduction

This chapter examines the history of the various attempts that have been made by the provinces and/or the federal government to promote electricity systems planning and development on a regional basis. The motivations behind these attempts and the reasons for their success or failure are also examined. This chapter makes the point that past attempts to promote *multi-provincial* electricity systems or institutions have not been successful. The main examples of this were attempts to create a Western grid, an Eastern grid and a Maritime grid. On the other hand, the chapter shows that certain *interprovincial* bilateral initiatives, some of which have been promoted by the federal government, have been very successful.

3.2 Multi-Provincial Initiatives

3.2.1 The Western Grid

Two major national grid initiative studies, the Federal-Provincial Working Committee on Long-Distance Transmission (1967) and the IPACE Study Supervisory Committee (1978), each recommended that, although a major national program of interconnections was not warranted, efforts at promoting greater regional interconnections might prove more fruitful. In the West in the 1970's, economic and political conditions combined to direct the utilities and provincial governments towards the idea of a regional power grid connecting the power systems of the four western provinces.

During the Western Premiers' Conference held at Yorkton, Saskatchewan in April 1978, it was announced that: "It is anticipated that a western power grid could produce significant economic advantages for the provinces in meeting their future electrical needs". A technical review team was set up to undertake a feasibility study of a power grid interconnecting British Columbia, Alberta, Saskatchewan and Manitoba. The report of this study, released in February 1979, concluded that substantial benefits could flow from the interconnection of the four provinces. However, there was a mixed reaction to this finding.

In general, the utilities were skeptical of the report's findings; they felt that the report overstated the benefits to be gained from a regional grid. Reaction from the provincial governments was more favorable, but still mixed. On August 9, 1979, British Columbia announced that the report presented insufficient grounds to justify its participation in the grid. Alberta had hired another consultant to review the report's findings. This second report was favorable enough to prompt the energy ministers of the three Prairie provinces to continue to examine a western grid proposal.

At this stage, the impetus behind the western grid initiative came mainly from the governments. The utilities, especially Calgary Power and Manitoba Hydro, remained unconvinced that a western grid would benefit them. Ministerial discussions over the next few months, prompted especially by Manitoba, kept the proposal alive. A Ministerial Committee was formed in early 1980; the efforts of this Committee led to the signing of the Western Electric Power Grid Study Agreement on March 27, 1980, by the provinces of Alberta, Saskatchewan, and Manitoba. Pursuant to this Agreement, a detailed cost/benefit analysis of the western grid proposal was undertaken by a Steering Committee and Study Directorate set up by the provinces.

The proposal to be studied was a transmission interconnection linking Manitoba, Saskatchewan and Alberta whereby Manitoba would sell 1000 MW of firm power to Alberta and 500 MW of firm power to Saskatchewan, over thirty-five years. The report of the Study Directorate, published in December 1980, recommended that a ± 500 kV high voltage direct current (HVDC) transmission line be constructed from Henday, Manitoba to Saskatoon and on to Calgary. This project entailed advancing of construction of hydroelectric projects on the Nelson River in Manitoba, commencing with the Limestone generating station, and delaying the construction of thermal and hydroelectric generating stations in Saskatchewan and Alberta. The estimated cost of this project from 1980 to 1987 ranged from \$1175 to \$1350 million in 1980 dollars.

The Western Electric Power Grid (WEPG) study included a cost/benefit analysis of the proposed sale of power, in contrast to the case if no sale were made, in order to determine the net benefits (if any) of the WEPG to each province's electrical system and to the region as a whole. The study also included assessments of the environmental and socioeconomic effects of the proposed power sale. Using data on system costs and planning supplied by the utilities, and various assumptions about capacity factors, load growth, costs, and revenues, the study concluded that the present value of net benefits to

the utilities (as a whole) from the WEPG was \$150 million. This represented the difference between the savings to Alberta and Saskatchewan, and the increase in costs for Manitoba and the WEPG transmission line. Under most contingencies viewed as "reasonable", the sale's net benefits were positive for the Prairie region.

The environmental impact analysis compared the effects to the environment of selected projects that would proceed under the WEPG with selected projects that would be developed by the provinces if the grid did not go ahead. This analysis concluded that the WEPG would have less harmful impact on the environment than if coal-fired thermal plants were constructed to supply 1000 MW in Alberta and 500 MW in Saskatchewan.

The study's socioeconomic analysis examined the direct and indirect employment and income effects of the proposed capital and operating expenditures under the WEPG. The result of this analysis was that very large increases in employment and income were predicted for Manitoba, and a moderate reduction of employment and income was predicted for Saskatchewan and Alberta. It was determined that there would be a net positive effect on the Prairie region: an increase in employment of 26 000 man-years and an increase in income of \$550 million. This section of the study concluded that the shift in labour demand from Alberta and Saskatchewan to Manitoba would be beneficial to the entire region, reducing demand in regions where labour shortages were forecast, and increasing it in a region with less labour demand.

The utilities in the provinces were not encouraged by the rather marginal benefits to them that the WEPG study predicted. An unpredicted change in any number of factors such as load growth rates or construction cost overruns could mean losses for the utilities under the WEPG. The proposed sale agreement was for thirty-five years; in that length of time energy prices could fluctuate wildly as they did during the oil crisis of the 1970's. Hence, in the negotiations which followed the study's release, a pricing agreement that equitably apportioned the risks to all three provinces was difficult to achieve.

Had the decision-making been left to the utilities, it is likely that consideration of the WEPG idea would have been suspended shortly after the release of the 1980 study. However, it was the economic and political conditions which were present in western Canada in the late 1970's that prompted the studies into the WEPG, and it was these same forces that motivated continued efforts to reach an agreement on the western grid.

The significant socioeconomic benefit of a western grid shown in the 1980 study was perhaps the single largest motivation behind the WEPG concept. From 1978 to 1980 it appeared that the WEPG project met the economic needs of the Prairie region. The economy of Manitoba was in recession in the late 1970's, and the provincial government was under pressure to do something to stimulate economic growth. In the Manitoba Legislative Assembly Throne Speech of February, 1980, mention was made of exploiting the province's hydro resources in order to revive the economy and provide a "significant stimulus to the construction industry". At the same time, the economies of Saskatchewan and Alberta were experiencing inflationary pressures because of a booming oil industry. In Alberta, planned heavy oil mega-projects promised to increase industrial expansion, while in Saskatchewan, several major power projects were under way in 1980. Thus the transfer of economic activity under the WEPG project from booming Saskatchewan and Alberta to depressed Manitoba was seen as beneficial by all three provincial governments.

Political considerations were also important in motivating consideration of the WEPG. In the late 1970's, the western provinces were in a struggle with the federal government over control of provincial energy resources. A successful WEPG arrangement would be a strong example of western cooperation and solidarity. The fact that the WEPG could be financed from the Alberta Heritage Fund, and without federal assistance, was not without significance. There was also a less tangible spirit of cooperation between the governments of Alberta and Manitoba. These two provinces would be the major stakeholders in the WEPG, as the major power sale would be to Alberta, and most investment would occur in Manitoba.

Under the direction of the WEPG Steering Committee, negotiations between the provinces aimed at producing a draft agreement on the WEPG were begun in 1981. There were difficulties in trying to reach an agreement. By June 1981 there was no agreement on the sharing of the costs and benefits among the provinces. One sticking point was a proposal that would give Manitoba the right to buy back power after eighteen years of the contract if Manitoba's own load growth exceeded the 3% per annum prediction used in the WEPG study. Nevertheless, in July 1981 the Steering Committee felt that an agreement was still possible, and an interim agreement was submitted to the Ministerial Committee in October 1981.

The political reaction to this interim agreement was mixed. On October 22, the premiers of Manitoba and Alberta announced that there was unanimous accord by the provincial energy ministers on the draft agreement. However, on October 23, the Premier of Saskatchewan announced that no interim agreement had been reached and that such an agreement was not possible until the work of the committees had been reviewed by the governments.

By now political factors were in play which would help to defeat the WEPG concept. In November a new government was elected in Manitoba. It was critical of the WEPG project and entered negotiations determined to ensure that Manitoba's interests were protected in the terms of any WEPG agreement. The new government paid more attention than its predecessor to the concerns of Manitoba Hydro officials. Manitoba demanded new terms at the negotiations to capture more of the benefits of the WEPG project for itself; most important among these was that Manitoba have the right to cancel the agreement after 20 years if the Limestone hydro station was needed to meet Manitoba's demand. Saskatchewan and Alberta would agree to this only if they were compensated for lost benefits.

Another delay in negotiations occurred because of a change of government in Saskatchewan in April 1982. Each province was becoming more sensitive to the risk of losses resulting from the WEPG as it became time to finalize the wording of an agreement; each province wanted the others to bear more risk in case of net loss. The beginning of the end to the WEPG agreement came in June 1982 when the Alberta government announced that it would suspend consideration of the WEPG for two years. This announcement came on the heels of Alberta's own preliminary studies which showed that hydro development on the Slave River in northern Alberta was feasible. The death knell for the WEPG project came soon afterwards on July 19, 1982, when the three provincial ministers announced their decision to postpone WEPG negotiations for at least two years due to "altered economic conditions".

By June, 1982, the combination of political and economic factors that originally had made the WEPG idea seem attractive had fallen apart. Negotiations over the terms of the power sale and the sharing of risks under the project had stalled. The underlying political and socioeconomic justifications were gone. Probably the most important reason for the failure of the WEPG was the recession that hit the Alberta and Saskatchewan economies in 1982 because of the slump in the oil industry. The lower employment and deferred

investment which would come with the WEPG would have been counterproductive in 1982. Alternative projects which might provide benefits greater than those offered by the WEPG captured the imaginations of the provinces. Alberta became interested in the development of Slave River hydro; Manitoba considered export sales of power to the U.S.

The federal government played only an incidental role in the development of the WEPG idea. From 1978 to 1981 there was no federal involvement in the discussions, but developments were monitored by the Electrical Energy Branch of the Department of Energy, Mines and Resources. The provinces might have taken advantage of a 1974 federal policy to provide loans for regional interconnections, but no request for financial assistance associated with the WEPG was made until Manitoba requested federal loans in January 1982. At that time Manitoba was trying to keep alive hopes that the WEPG would go ahead, but it wanted federal assistance in order to mitigate the high cost of financing the construction of the Limestone generating facilities. The federal view was that the marginal benefits to the energy industry from WEPG would not justify assistance under federal energy policy.

However, the federal government considered giving assistance to Manitoba under regional economic development policy as the construction of the Limestone hydro project would provide a stimulus to Manitoba's economy. Federal consideration of the latter idea was discontinued in 1984 when Manitoba signed an export contract with Northern States Power Corporation of Minneapolis, allowing them to complete the construction of Limestone.

Some of the anticipated benefits of the WEPG were achieved without it. Alberta Power and SaskPower put a HVDC interconnection line in service in 1989. TransAlta and B.C. Hydro established an interconnection between B.C. and Alberta in 1986 which allows for power sales and an opportunity for Alberta to export power to the U.S. In June 1984 Manitoba Hydro signed a 12-year contract for the sale of 500 MW of firm power to Northern States Power. There were also summer and seasonal diversity sales.

3.2.2 The Eastern Grid

The mid-1970s was a difficult time for the electricity supply industry in eastern Canada. Most utilities in the region were relatively small, isolated from major sources of

hydroelectric power, and highly dependent on oil-fired thermal generation at a time of escalating petroleum prices. Largely for these reasons, calls for a coordinated approach to the solution of electricity supply problems in the region came from several of the provinces of eastern Canada.

The importance placed on energy issues in the mid-1970s resulted in two Federal-Provincial Conferences on Energy in that era, one in January 1974 and another in April 1975. There was a consensus among eastern Canadian provinces that regional electricity initiatives were needed to some extent. A Québec position paper tabled at the 1974 Conference called for the creation of an intergovernmental Energy Programs Planning Board to engage in interprovincial planning on a formal basis.¹ At that same Conference, New Brunswick expressed its desire to see the construction of high voltage transmission facilities connecting Ontario and Québec to the Maritimes, so that the Maritime provinces might have access to surpluses of energy available in other regions of the country.²

At the 1975 Conference two of the most isolated provinces, Nova Scotia and Newfoundland, sought Ottawa's help to gain access to surplus energy elsewhere in the country. Nova Scotia asked the government of Canada to "provide the leadership in the construction of an eastern Canadian power grid that would enable the distribution and sale of Newfoundland and Québec hydroelectric power throughout the Atlantic Provinces".³ Nova Scotia was of the opinion that an eastern Canadian grid would improve the prospects for nuclear and tidal development in the region, and reduce oil dependency. Newfoundland called for the establishment of a national power grid which would "permit the early development of renewable hydro resources and permit the free movement of this form of energy to any area of the country requiring such energy".⁴ Provincial efforts in this area during those years led in many directions. As stated previously, the federal government was reconsidering the idea of a national grid and the provinces investigated such a proposal under the auspices of the Inter-Provincial Advisory Council on Energy. Discussion of the formation of a Maritime Energy

-
- 1 Government of Québec Position Paper on Energy, tabled at the January 1974 Federal - Provincial Conference on Energy, p. 29.
 - 2 Statement by New Brunswick Premier Richard Hatfield, 1974 Federal - Provincial First Ministers' Conference on Energy, VERBATIM REPORT, Canadian Intergovernmental Conference Secretariat, p. 304.
 - 3 Statement by the Province of Nova Scotia at the Federal-Provincial Conference on Energy, April 1975.
 - 4 Statement by the Province of Newfoundland at the Federal-Provincial Conference on Energy, April 1975.

Corporation began not long after the 1975 Energy Conference. Another initiative that was born in this period was the proposal for an eastern Canadian grid.

In 1975 the Montreal Engineering Company and the Shawinigan Engineering Company co-authored two briefs. One, entitled "Regional Planning of Electrical Energy in Eastern Canada", examined the future of the electricity industry in eastern Canada over the next twenty-five years. The other, entitled "Energy-Eastern Canada Region", proposed a study into the feasibility of the development of Bay of Fundy tidal power in a regional context. The first of these briefs emphasized the need for planning and policy-making on a regional basis in order to meet the electricity demand of the future. These companies predicted that peak demand in the eastern Canada region would rise from 31 600 MW in 1973 to 170 000 MW by the year 2000. The generation mix was expected to change from 75 percent hydro : 25 percent thermal in 1975 to 60 percent thermal : 40 percent hydro in 1995.⁵ These briefs were intended to prompt studies of a regional approach to the development of electric systems in eastern Canada.

In September 1975 the Premiers of Québec and the four Atlantic provinces decided to study the idea of a regional grid. The purpose of the study was to examine the advantages which could be obtained from increased interprovincial interconnections. The study focused on the advantages which could be obtained in the short term from the use of interconnections to transmit hydroelectric surpluses from one area in the region to another. With respect to the longer term the study examined the advantages that might be obtained by using increased interconnections to transmit the output of the proposed Gull Island project in Labrador.

A Committee on Interconnections Between Québec and the Atlantic Provinces was struck to direct the study. The aim of the study was to determine the technical means by which the five eastern provinces could share to best advantage their energy resources to meet their collective needs. The method of the study was first to identify possible surpluses of hydroelectricity in the region over the period 1977 to 1985, and then to determine the best short-term allocation of those surpluses within the region to replace thermal generation. The proposed allocation of surplus hydroelectricity was done in such a way as to maximize the amount of fossil fuel replaced, so long as this was economically viable. It was intended that surplus hydroelectricity would replace the least efficient oil-fired

5

Montreal Engineering Company, Limited and The Shawinigan Engineering Company Limited, REGIONAL PLANNING OF ELECTRICAL ENERGY IN EASTERN CANADA: A BRIEF, June 1975, p.4.

generation units wherever they were in the region. The limits imposed by transmission losses and transmission capabilities were also considered in this analysis.

When the Premiers decided to undertake this study in September 1975 it was expected that both Newfoundland and Québec would both have substantial hydroelectric surpluses at their disposal from 1977 to 1985. Soon after the study was begun however, Québec reduced Hydro-Québec's capital spending budget for 1976, slowing its construction program, and Newfoundland announced the postponement of its Gull Island hydroelectric project. Thus the study proceeded on the basis that only Québec would have hydroelectric surpluses available in the short-term. The study assumed that Gull Island power would be available beginning in 1982 and considered the implications that this would have in the longer term.

Two possible scenarios were considered by the study group. Scenario 1 covered the possibility that Newfoundland might construct a transmission line connecting the Island of Newfoundland with the Churchill Falls generating station in 1982 and begin recalling 300 MW of power from that station⁶; Newfoundland has an option to do so under its 1969 power contract with Hydro-Québec. In Scenario 2 Newfoundland was not connected to Churchill Falls; therefore, all of Québec's hydroelectricity surplus would be available for distribution to the Maritimes.

Three options for the eastern provinces were developed under each scenario. In Option 1 surpluses would be routed using existing transmission systems and interconnections, as well as those expansions already being planned by the various utilities. Option 2 called for some additional modifications to be made to the Québec system in order to allow 450 MW to be delivered to New Brunswick at all times. These modifications called for an increase in investment of \$53 million above Québec's present plans. Option 3 would make it possible to deliver 800 MW at all times at the Québec-New Brunswick border. This last option would require Québec to spend \$114 million and New Brunswick to spend \$69 million on improvements to facilities in addition to their planned construction programs.

The study estimated how much energy could be substituted and how much oil could be replaced under each option and scenario. If Option 1 were chosen the amount of

hydroelectric energy substituted for thermal generation from 1977 to 1985 would range from 19 505 GWh (scenario 1) to 21 734 GWh (scenario 2), replacing between 32.7 million and 36.2 million barrels of oil in the same period. Under Option 2, between 20 034 GWh and 22 334 GWh of thermal energy would be substituted and between 33.6 million and 37.1 million barrels of oil would be replaced. Under Option 3, between 21 378 GWh and 25 397 GWh of thermal energy would be substituted and between 36.6 million and 41.6 million barrels of oil would be replaced.⁷

In order to be able to draw conclusions and make recommendations, the study considered the economic, technical, balance of payments, and environmental consequences of the various options. The analysis of available surpluses had shown that Québec would not have sufficient surpluses of hydroelectricity to be able to supply 800 MW nor even 450 MW to New Brunswick at all times. Oil prices were expected to range between \$14 and \$17 per barrel in the 1977-1985 period. These figures led the study group to conclude that under Option 1 the total savings from replaced oil would be between \$462 million and \$612 million. Under Option 2, with an additional investment of \$53 million, the total savings would be between \$476 million and \$629 million. Under Option 3, with an additional investment of \$183 million, the total savings would be between \$518 million and \$714 million. If Gull Island power became available in 1982, and the Island of Newfoundland was connected by a transmission line to Labrador, then an additional 30 million to 42 million barrels of oil (\$420 million to \$714 million) could be saved in the 1982-1985 period.⁸

The study group concluded that the increased interconnections required by Options 2 and 3 were not warranted, at least not in the short term. The additional savings which might be gleaned from reduced purchases of oil would not make up for the cost of the additional investment in the 1977-1985 period. Without any changes in the utilities' construction plans, 33 million to 36 million barrels of oil could be replaced by directing surplus hydroelectric power from Québec to Atlantic Canada. The proposed additional investments would save only another 4 million to 6 million barrels.

With a view to the longer term, beyond 1985, the study group suggested that with Gull Island in service it would become more attractive to increase the intertie capacity between Québec and New Brunswick. If a significant proportion of Gull Island's output

7 Ibid., p.II-18.

8 Ibid., p.III-6.

was to be available to the Maritime provinces over many years, then the investment in increased interties would be justified. The study report recommended that additional studies continue on these long-term prospects.

Besides the economic benefits there were some ancillary benefits to be had from the sale of hydroelectric surpluses from Québec to the Maritimes. The study report identified some technical benefits that could be realized by the systems of the provinces concerned. There would be benefits from lower reserve requirements, improved stability and reliability, and some load diversity benefits. However, as Québec had a relatively large system, the Atlantic provinces had more to gain from such benefits.

The study report concluded that Canada's balance of payments would also benefit from the proposed sales of hydroelectricity. The Canadian currency would be strengthened by the accompanying reduction in oil imports. However, the study report recognized that export of hydro surpluses to the United States could have the same beneficial effect, and even a potentially greater effect on the balance of payments if the surpluses could be sold in export markets at a price higher than that which would be paid by the Atlantic provinces.

It was concluded that the environment would also benefit from an eastern Canadian grid. Québec's hydroelectricity would replace some thermal generation in the Atlantic provinces. It was calculated that air pollution in those provinces would be reduced by 2 percent.⁹ Furthermore, the potential saving of 30 million to 40 million barrels of oil would contribute to Canada's goal of conserving non-renewable energy sources. The only negative impacts on the environment would come if Options 2 or 3 were exercised, in which case more land in Québec would be required for additional transmission lines.

The study report of the Committee on Interconnections Between Québec and the Atlantic Provinces was released in March 1976. Despite the fact that the study pointed to some obvious benefits available at little cost to the participating provinces, no sales of the type suggested were made by Québec to the Maritime provinces. No new interconnections between Québec and New Brunswick were constructed until 1985, when a ± 80 kV back-to-back DC interconnection and a 345 kV transmission line were put in service. In the

years following the eastern grid study Québec became more interested in exploring opportunities to sell surplus hydroelectricity in the United States than in Atlantic Canada.

It seems that the study's recommendations were overtaken by the events of the time. Newfoundland had begun to talk of attempting to re-open the Churchill Falls power contract. In 1976 the Maritime provinces and the federal government began negotiating the formation of a Maritime Energy Corporation; the Maritime provinces were evidently keen on pursuing a much more integrated and long-term type of cooperation than that offered by the eastern Canada grid study. In April 1976, one month after the release of the Committee's report, the governments of all provinces agreed to participate in a study of the feasibility of a national grid to be conducted by the Inter-Provincial Advisory Council on Energy. The provinces still evinced a desire to cooperate, but they had directed their attention to other initiatives.

3.2.3 The Maritime Energy Corporation

From 1976 to 1979 discussions were held among the three Maritime provinces and the federal government aimed at the formation of the Maritime Energy Corporation (MEC). The MEC was to be a regional generation and transmission utility, jointly owned by New Brunswick, Nova Scotia, Prince Edward Island and the federal government. The proposed MEC would have coordinated the entire Maritime bulk generation and transmission systems and engaged in regional planning, and research and development. In the end, the MEC was not formed because of a lack of agreement for a variety of reasons between the provinces and the federal government. The conditions which were present in the Maritime provinces in 1976, which gave support to the MEC concept, were no longer enough by 1979 to overcome the differences which had arisen among the parties as they negotiated the specific terms of an agreement.

The electricity supply industry in the Maritimes was in a state of difficulty in the mid-1970s, and this difficulty made the provincial governments and utilities receptive to the federal government's efforts at bringing about regional cooperation. The oil-price shocks of the 1970's had hit the Maritime utilities particularly hard as they were more dependent on oil than were utilities in other regions of Canada. Before a submarine cable connected Prince Edward Island with New Brunswick in 1977, P.E.I. was totally dependent on oil

for electricity generation.¹⁰ In 1976 New Brunswick was 43 percent dependent on oil and Nova Scotia was 62 percent oil-dependent.¹¹ Fuel costs and electricity rates had risen rapidly in recent years and it was expected that this trend would continue unabated into the future. In addition, the relatively small Maritime utilities could not afford the financial risk associated with developing large generation projects.

The federal government had a stake in ensuring that the Maritime electricity supply industry was as efficient as possible. For years the federal government had been providing financial assistance in response to requests from the Maritime utilities. Such requests were likely to continue, and the federal government wished to derive the greatest possible results from its investment. Federal assistance in the form of loans and grants had come in the past under the Atlantic Provinces Power Development Act (passed in 1958) and under the Atlantic Development Board. These were replaced by assistance from the Department of Regional Economic Expansion (DREE) in 1969. DREE encouraged the Maritime utilities to view power facilities as being for the whole region, yet regional integration never took place.

Until the advent of the MEC concept, the best example of regional cooperation was the Maritime Power Pool (MPP), an organization founded in 1959 by the utilities of New Brunswick and Nova Scotia. The member utilities of the MPP had realized some of the benefits that cooperation produces, from interconnections and the coordination of operations, but the MPP did not engage in long-term joint planning and did not work toward regional solutions to problems.

The MPP had asked for federal financial assistance in both 1971 and 1972 in order to strengthen the interconnection between the two provinces. The federal government was reluctant to grant more assistance unless some form of common planning and coordination was adopted. In 1974 Ottawa decided to promote more actively regional cooperation with the announcement of its regional interconnections policy. Under this policy the federal government would pay 50 percent of the cost of interconnection studies and would provide loans of up to 50 percent of the cost of improving existing regional interconnections, at Crown corporation rates. A new nuclear energy policy was the second feature of this initiative. The federal government would offer loans of up to 50

10 ELECTRIC POWER IN CANADA 1976, Department of Energy, Mines and Resources, 1976, p.7.

11 THE MARITIME ENERGY CORPORATION—AN HISTORICAL ACCOUNT, Anne M. Lawson, Electrical Energy Branch, Energy, Mines and Resources, August 1987, p.III-3.

percent of the cost of the first nuclear unit in a province, and would offer the same loans for a second unit in a province provided it was for regional application.

Canada suggested that both types of nuclear loans could be made to New Brunswick, which was going ahead with its own nuclear generating program. It was contemplated that New Brunswick might build two nuclear units, one of which would be for regional application. However, no agreement could be reached between the federal government and New Brunswick on the site of the second unit.¹² Only one unit was built, at Point Lepreau, and a \$350 million federal loan agreement through Atomic Energy of Canada Limited was signed in January 1976.

In the early 1970's there was a convergence of circumstances that made the idea of a regional Maritime utility seem feasible. There were problems in each Maritime province that might be best addressed by a regional solution. Prince Edward Island was studying the feasibility of a submarine cable to connect it to New Brunswick by 1976. This study was done with federal financial assistance. Nova Scotia was asking for federal assistance to ease the burden of rapidly increasing consumer electricity rates. New Brunswick needed to sell some of the power that would come from Point Lepreau, in order to reduce its share of the financial risk of the project.

Ottawa provided the leadership to begin consideration of a regional Maritime utility. On June 22, 1976, the federal government wrote to the three Maritime governments, inviting them to participate in studies aimed at finding the most appropriate organizational structure for the region's electricity supply industry. By September 1976 the three provincial governments had responded to the letter. The responses were favourable, but New Brunswick expressed concern that joint planning in the region might limit that province's benefit from its external interconnections.

New Brunswick itself had developed interconnections with Québec and Maine, and was considering using them to sell some of the power from Point Lepreau. Obviously, any transmission of power between the Maritime region and the United States or Québec would have to go through New Brunswick. On the other hand, New Brunswick Power welcomed the idea of a regional utility. NB Power wanted P.E.I. and Nova Scotia to share the risk of the Point Lepreau project, and felt that federal assistance was necessary

12 Ibid., pp.III-8 to III-9.

to make it happen. In October 1976 NB Power produced a document called, "Proposal for a Maritime Energy Corporation" which was the first specific outline of what the MEC's objectives would be. The document suggested that the Point Lepreau nuclear station be the MEC's first jointly-owned endeavour.

In November 1976 officials from the utilities and the federal government agreed to share the cost of a feasibility study of the proposed MEC. In December the three Maritime Premiers agreed that "broadly speaking" they were in favour of the MEC concept. By February 1977 the Study Coordinating Committee had agreed on the objectives of the MEC, which were published in slightly altered form in the feasibility study report:

1. To provide a competent system planning staff to carry out regional planning of the generation and bulk transmission system supplying the three Maritime provinces.
2. To finance and build projects, and assume responsibilities related to regional generation stations and associated transmission construction, maintenance and operation, and such other related duties as may be appropriate.
3. To coordinate and direct within agreed contractual conditions, the day-to-day operation of the entire Maritime system generation and bulk transmission facilities, to achieve the least total cost supply possible and to assign benefits and costs to each of the utility partners in accordance with their rights.
4. To optimize the regional benefits which are achievable from transmission ties external to the region while recognizing specific provincial rights.
5. To engage in research and development, energy conservation, and load management projects on behalf of the Maritime utilities.¹³

These five objectives were agreed to in principle by the federal and provincial governments on February 1, 1977.

Work on the MEC feasibility study was begun well before the official agreement on its undertaking was signed on June 21, 1977. The report on the feasibility study was

published the following July. The Study Committee recommended that the MEC be formed, with the proviso that there were three preconditions which must be met in order for the MEC to succeed. The conditions were:

1. that the Point Lepreau nuclear and Lingan coal (Nova Scotia) generating stations be included as the MEC's first projects.
2. that the MEC should develop any extensions to existing interconnections and any new interconnections external to the region. New Brunswick would continue to own and administer existing interconnections.
3. that specific forms of federal financing be available.¹⁴

Besides making these recommendations, the feasibility study identified several issues which would have to be resolved in negotiations in order for the MEC to be incorporated. In fact, it was essentially because these issues remained unresolved that the MEC never came into being. Project choice was the first stumbling block for negotiators. It was considered essential to include Point Lepreau as one of the MEC's first projects in order to meet New Brunswick's need to share its risk and to give the MEC a credible beginning. However, both Nova Scotia and Prince Edward Island were wary of the risk inherent in such a large project. Moreover, there was opposition to nuclear power in both of these provinces. Nova Scotia feared that the use of nuclear power would adversely affect its coal industry.

The fate of New Brunswick's external interconnections would also trouble negotiators. NB Power insisted that it retain control over existing interconnections, as it alone had taken the risk for their development. However, because that would mean that NB Power's interconnections would compete with those developed by the MEC, other participants felt that the MEC would not function effectively unless it eventually took control of all interconnections.

The composition of the MEC executive staff also divided the negotiators. The federal government would not commit itself financially to the new organization unless it had its own full-time staff who would act in the best long-term interest of the region. The

14 Ibid., pp.3-4.

Maritime utilities were afraid of losing their responsibilities too quickly to the new organization; NB Power wished the job of Chief Executive Officer of the MEC to be held initially by a staff member of an existing utility, so that the new utility might be sensitive to the concerns of those it succeeded. The feasibility study report recommended that the first Chief Executive Officer and first Chairman of the Board be recruited from executives of the participating utilities. This would be an interim arrangement until the MEC had its own full-time executives.¹⁵

The feasibility study recognized that there would have to be agreement on the legal powers of the MEC and on the extent to which it would be subject to federal regulation. All of these issues were components of the general difficulty inherent in the formation of the MEC - the loss of autonomy by the provinces and utilities and their fears of undue federal influence and interference. They realized that some sacrifices were a necessary part of MEC participation, but they were suspicious that the benefits were not worth what they were losing in decision-making power.

The reaction of the provinces to the report indicated how difficult it would be to reach an agreement on the MEC. It seemed that progress among utility and federal officials had outpaced the thinking of the provincial governments among which there was a lack of consensus even on some issues basic to the MEC. There seemed to be a lack of will in P.E.I. and Nova Scotia which began to slow the momentum of MEC negotiations. For example, although Nova Scotia Power had agreed that the Lingan coal plant would be part of the MEC it had not received provincial approval.

The MEC negotiators felt that now was the time to obtain the federal financing guarantees recommended by the Study Committee. Federal financing would share the risk of Point Lepreau and make it an attractive investment for the Maritime utilities. The Study Committee had recommended that there be federal financial participation in all MEC projects in order to compensate the provinces for their loss of autonomy. The Study report recommended that one of two alternative forms of financing be adopted. The first was a combination of federal equity and loans up to 50 percent of the cost of projects. There would be federal long-term take-or-pay contracts for 50 percent of the power output of projects with a capital cost over \$600 million, with identical agreements for sale to the utilities. Federal guarantees would cover non-completion or abandonment

of all projects. The second financing option involved federal equity participation only, with no loans. The federal government would contract for 100 percent of the output and sell it back to the utilities.¹⁶ Ottawa would be putting up much less money under this second plan; and it was favoured by the Department of Energy, Mines and Resources.

A federal financing plan was slow in coming, however, because of difference of opinion between the Departments of Finance and EMR over the scope of federal assistance needed. The Department of Finance thought that the federal government should minimize its involvement in a risky venture; only loans should be provided, with no other federal guarantees. EMR felt that although MEC was an economically sound project, federal equity participation and guarantees were necessary to encourage the provinces to commit to the MEC. In October 1977 the government of P.E.I. wrote to the Minister of Energy, Mines and Resources warning him that the Maritime governments needed to be assured of a federal financial commitment or the momentum of the MEC concept would be lost.

In November the Department of Finance agreed there would have to be federal involvement in the MEC for it to succeed. Cabinet accepted in principle the feasibility study recommendation that Canada guarantee the risk of MEC projects. EMR was authorized to negotiate the details of a financial agreement. The Minister of Energy, Mines and Resources called the Maritime Premiers to a meeting on January 23, 1978 to discuss the details of federal participation in MEC projects in a combination of equity, debt and guarantees.

At the end of that meeting, the four participants announced that they would instruct their officials to negotiate the articles of association for the incorporation of a Maritime Energy Corporation. It was agreed to provide the MEC with an initial capitalization of \$10 million, half of which would come from the federal government. The MEC's first project, after Point Lepreau, was to be the second phase of the Fundy tidal power development study. This was a key factor in securing Nova Scotia's support for the MEC.

The apparent harmony after this meeting belied the discord that existed. By April it was clear that the provinces and federal government could not agree on the outcome of the

¹⁶ Ibid., pp.30-31

February meeting. The federal government's view was that it had been settled that federal participation in MEC projects would be at 5 percent of equity; the provinces felt that this was only one of many options. The major disagreement was over the refinancing of the Point Lepreau project. Ottawa wanted that issue to be settled as part of the agreement to form the MEC; while the provincial governments wanted the federal government and NB Power to negotiate financial guarantees for the project before it was turned over to the MEC.

New Brunswick was quite adamant that the federal government provide refinancing for Point Lepreau as a precondition for New Brunswick's entry into the MEC. New Brunswick's position was that as it had begun a nuclear program rather than build another thermal station only because of Ottawa's 1974 nuclear support policy, Ottawa should bear the additional risks. New Brunswick asked for a non-performance guarantee, a capital cost guarantee, an abandonment guarantee and extended amortization of its loan from the federal government.

The federal government was not forthcoming with a positive response to all of New Brunswick's demands. In June, Cabinet offered a performance guarantee which would provide up to \$1.5 million for each 1 percent that Point Lepreau's output fell below 75 percent capacity. Cabinet further offered to refinance Point Lepreau as an MEC project with 4.8 percent federal equity. Negotiations with NB Power, and the battle over financing plans between EMR and the Department of Finance, continued over the summer.

By the end of the summer the provincial negotiators agreed that the financing proposal presented by EMR best met their needs. EMR proposed that ownership of Lepreau be transferred to the MEC. All four participants would contribute equity totalling 10 percent of Lepreau's cost, with the maximum federal share at 4.8 percent. Canada would buy the output and sell it to the MEC which would in turn sell it to the utilities.

With some agreed modifications, this financing plan was presented to the provincial governments on December 18, 1978 and the reaction seemed favourable. In February 1979 the federal Cabinet approved this financing proposal, resolving that no further federal government support could be provided. This last period of real progress in MEC negotiations culminated in the signing of a Memorandum of Understanding (MOU) by the Maritime Premiers and the federal Minister of Energy, Mines and Resources on

February 16, 1979. The four participants agreed to sign a Principal Agreement to establish the MEC by May 1, 1979.

The MOU was intended to "further the general objectives set out in the MEC Feasibility Study" and to serve as a guide for the negotiators of the Principal Agreement. The MOU stated that the basic principle "in a joint approach to power development in the region [is that], each provincial participant will, in the long run, receive an equitable share of benefits in relation to the position it could have achieved with individual system development".¹⁷

The following are some of the main points of the MOU. The MOU reiterated the five objectives of the MEC contained in the feasibility study report. It was agreed that the MEC would buy Point Lepreau from NB Power as its first project. NB Power would retain full ownership of existing interconnections with Québec and Maine, until a satisfactory agreement to transfer them to the MEC was reached; the MEC would have the right to build all future interconnections and use them for the benefit of the region. NB Power would draw no more loans from AECL after March 31. Any major Fundy tidal power projects would be done through the MEC. The MOU set out basic terms for equity participation in the MEC; Canada would hold a 48 percent share of total equity and the other 52 percent would be divided among New Brunswick, Nova Scotia and Prince Edward Island. To ensure a strong credit rating for the MEC, it was agreed that Canada would enter into an all-events, take-or-pay contract for all of Point Lepreau's output, and the provincial utilities would enter into identical contracts to purchase the power. Finally, the MOU contemplated that there would be no federal involvement in MEC projects initiated 15 years after its incorporation, and that participation in individual projects would be determined on a project-by-project basis as agreed by the shareholders.

As it turned out, the semblance of agreement represented by the Memorandum of Understanding was illusory. A new wave of negotiations after the signing of the MOU could not produce detailed agreements. By the summer of 1979 it was evident that the provinces no longer evinced the spirit of cooperation necessary for the formation of the MEC.

17 Memorandum of Understanding Between Canada, New Brunswick, Nova Scotia, and Prince Edward Island, February 16, 1979, p.1.

On April 23, 1979, a new government was elected in Prince Edward Island. On the basis of its policy against nuclear power, it announced that it wished to withdraw from participation in the Point Lepreau project while remaining a member of the MEC. This was contrary to the policies of the Island's utility, Maritime Electric, which had once argued that P.E.I. should buy a 5 percent share in Lepreau. The MEC negotiators had considered a policy of allowing provinces to opt out of some MEC projects, but no one expected that it would apply to Lepreau, which was the cornerstone of the MEC's formation. Therefore, the other parties said that P.E.I. could not be in the MEC without participating in Lepreau, and as a result P.E.I. withdrew from MEC negotiations.

Nova Scotia's initial enthusiasm for the MEC was being undermined by a growing suspicion in the province that the MEC would give priority to New Brunswick's interests over Nova Scotia's. The current cost estimate for Point Lepreau was double the initial one, and Nova Scotia feared it would go higher still. Nova Scotia became more concerned with developing its own Cape Breton coal and Fundy tidal resources; it felt that these developments would be delayed under the MEC which was more interested in New Brunswick's nuclear program.

The Point Lepreau project was the linchpin of New Brunswick's commitment to the MEC. As New Brunswick would be giving up control over external interconnections, it wanted to be sure that it would be better off under the MEC than it would have been without it. The major benefit of MEC participation to New Brunswick would be the sharing of the risk of Point Lepreau. As P.E.I. and Nova Scotia showed signs of weakening their commitment to the MEC, New Brunswick became convinced that without a further increase in federal financial support for Point Lepreau it could not participate in the MEC.

In July of 1979 the Premier of New Brunswick wrote to the federal Minister of Energy, Mines and Resources to present four conditions that would have to be met before the MEC could be established:

1. The proposed federal government support would have to provide an AAA credit rating.
2. The federal government would have to confirm its support for all approved MEC projects.

3. MEC must be the "instrument" of only the provinces.
4. MEC must never compromise provincial jurisdiction - the provinces should never be prevented from achieving benefits which would have developed outside the MEC.

Moreover, NB Power now wished to retain control of the operation and construction of Point Lepreau even when the plant's ownership was transferred to the MEC.

It was apparent by the summer of 1979 that the provinces were no longer in favour of the MEC. The New Brunswick Premier's letter implied that the MEC was something that Ottawa sought to impose on the provinces. It was true that the federal government had initiated discussions on the MEC, but it was to be an organization primarily for the benefit of the provinces. The necessary will to cooperate was gone, and it was not the federal government's intention to persuade the provinces to participate in an organization they did not want. However, Ottawa did offer more financial concessions in response to New Brunswick's request despite the earlier Cabinet decision that no further offers of federal assistance would be made. There would be federal equity participation of 4.8 percent of Point Lepreau's total cost, and the same participation was guaranteed for all MEC projects for the next 15 years.

This last federal offer could not make up for the provinces' lack of faith in the MEC concept. In October 1979 the Maritime Premiers announced that they no longer supported the MEC plan contained in the Memorandum of Understanding. The Premiers suggested a new structure for the Maritime Energy Corporation which would not involve joint ownership by the provinces of the MEC's projects. Ottawa was not enthusiastic about this proposal and negotiations were terminated. In the end the Maritime Energy Corporation was not formed.

The only new regional structure to come out of the MEC negotiations was the Coordinating Committee of Maritime Electric Utilities (CCMEU), formed in 1980. This is a planning and study group which makes recommendations to the provinces. CCMEU is made up of officials from the Maritime utilities, with observers from the federal and provincial governments.

Some of the benefits of the MEC were achieved without it. A submarine transmission link between P.E.I. and New Brunswick was built through which P.E.I. receives 69 percent of its electricity.¹⁸ This increases to 87 percent when the 20 MW supply from the jointly-owned Dalhousie plant in New Brunswick is taken into account. New Brunswick completed Point Lepreau on its own (with federal financing) and developed new interconnections and export markets with Québec and New England. Nova Scotia built the Lingan coal generating station, supplied by coal from the province's mines, which was supported by federal government investments.

However, some of the MEC's benefits were forgone. For example, P.E.I. and Nova Scotia lost the benefits they would have achieved from the ability to share New Brunswick's interconnections with Maine and Québec.

The novelty and complexity of the MEC proposal made it very difficult for the provinces and the federal government to agree on the specific details of its operational structure. Although the provinces originally agreed in principle that the MEC would be of benefit to each of them, during the negotiations each one became concerned that it would bear more of the risks and share less of the benefits of the MEC. These concerns grew inside the provincial governments despite the apparent conviction of most federal government and utility officials that the MEC was a sound proposal.

The failure of the MEC negotiations points out that for the success of a regional cooperation initiative, political consensus is as important as the appeal of economic benefits and the approval of the industry. From early on the MEC negotiators failed to ensure that the provincial governments were informed and supportive of what they were doing. Too often the thinking of the federal and utility officials outpaced that of the provincial governments; the federal and utility negotiators would come to an agreement on an issue, only to have negotiations stall when the provincial governments announced that it wasn't quite what they had in mind. There were even significant differences of opinion between provincial governments and provincial utilities, even *provincially-owned* utilities, which developed from time to time. It is not surprising that a regional consensus was not reached when often there was no consensus within a province.

18 ELECTRIC POWER IN CANADA 1988, Energy, Mines and Resources, 1989, p. 19

The experience of trying to form the MEC suggests that the political dimension of such a proposal requires to be addressed directly, as well as the technical, economic and financial problems. Unfortunately for the MEC, it was difficult to quantify its risks and benefits, and difficult to detail a structure which would apportion them fairly among the provinces. The failure of the MEC negotiations came down to a reluctance on the part of the provinces to give up decision-making power in return for regional benefits. Provincial self-interest was the acid test of each province's commitment to the MEC; in the end each province felt that its own interests would be best served on its own rather than under the specific proposals that were presented for the MEC.

3.3 **Bilateral Initiatives**

3.3.1 **Introduction**

It might be concluded from the above discussion that Canadian utilities have not been eager to reap the benefits which can be achieved from interconnection with neighbouring systems. However, such a conclusion would be incorrect since there are extensive interprovincial interconnections in place. For years Canadian utilities have cooperated with utilities in neighbouring provinces through bilateral agreements which have provided for the construction of interties, sales and exchanges of electrical energy, sharing of reserve capacity, etc. In the late 1980's, there were 33 major interprovincial interconnections, with a total design capability of about 10 000 MW.

The number of bilateral initiatives is too great to catalogue each one of them here.¹⁹ Many have involved interconnections of a relatively low voltage connecting an isolated section of one province's system with the electrical system of another province. There have been, and are presently in place, countless agreements for the sale of small and large amounts of firm and interruptible power, and agreements for emergency assistance, etc. Indeed, on many occasions neighbouring utilities have recognized the benefits to be obtained from cooperation and the integration of their systems, and entered into agreements to realize those benefits. Some of the more significant bilateral initiatives are discussed in this section. The federal government's role in promoting bilateral cooperation between utilities is also examined.

¹⁹ For a list of interprovincial interconnections see the table entitled "B2. Chronology of Regional Interconnections" in Appendix B of *ELECTRIC POWER IN CANADA 1988*, Energy, Mines and Resources Canada, 1989, p.95.

As noted in Section 3.2, the federal government has created policies designed to promote interconnections and cooperation among provincial utilities. The policies that were examined above in the context of regional cooperation were also employed to promote bilateral cooperation. The Atlantic Provinces Power Development Act (APPDA) was one such federal initiative. Enacted in 1958, the APPDA provided for subventions on the cost of Maritime coal used for power generation in New Brunswick, Nova Scotia and Newfoundland. The APPDA also provided for long-term loans at Crown corporation rates to provincially-owned electric utilities. These loans were available to finance thermal power generation projects. In 1969, the federal Cabinet decided to end the program of assistance provided under the APPDA. This assistance was replaced by a new policy of providing support for projects of major significance to regional power systems through programs of the Department of Regional Economic Expansion (DREE). Total subventions paid under the APPDA were \$21.8 million and total loans were \$218 million.

In January 1974, the federal government announced a new policy to promote regional interconnections. Ottawa would provide financial assistance for the study and construction of major transmission lines which permit regional interchanges of electricity. Under this policy, the federal government offered to consider: (i) paying up to 50 percent of the cost of studies of proposed interconnections; and (ii) financing up to 50 percent of the capital cost of approved interconnections, by providing loans at Crown corporation rates. There are several preconditions to be met in order to be eligible for financial assistance under this policy: (i) the resources of the province or utility must be inadequate to finance the interconnection; (ii) the interconnection must be economically justifiable in the long run; (iii) the interconnection must result in energy conservation, increased security of supply, or rationalization of energy costs; and (iv) special attention must be given to Canadian industrial and employment benefits from construction of the interconnection.

3.3.2 New Brunswick - Nova Scotia Initiatives

In the same year that the APPDA was enacted (1958) NB Power and the Nova Scotia utilities - Nova Scotia Power Commission and Nova Scotia Light and Power Company - undertook a study which demonstrated that there were definite economic benefits to be had from an interconnection of the two provinces' electrical systems. This led, in November 1959, to an interconnection agreement among the three companies which

provided for the formation of the Maritime Power Pool and the construction of a 138 kV interconnection. Loans for this project were provided under the APPDA, through the Northern Canada Power Commission. The loans were to be repaid over a 40-year period. The interconnection, linking Moncton N.B. to Macan N.S., came into service in 1961.

In 1963, the two provinces began to study future transmission linkages, and this led to the completion of a second 138 kV intertie in 1965. This too was financed under the APPDA. In the same year, NB Power purchased 25 MW of capacity, for one year, in Nova Scotia Light and Power Company's Tuft's Cove 100 MW thermal generating plant. This enabled NB Power to defer expenditures on its own planned 100 MW facility at Courtenay Bay.

In July 1972, the Maritime Power Pool submitted a request for financial assistance to the federal Department of Regional Economic Expansion in order to strengthen the New Brunswick - Nova Scotia interconnection. Ottawa responded by offering a \$1.5 million grant in support of the proposed new 345 kV interconnection, provided that the two provinces engage in integrated systems planning. The provinces were reluctant to accept this condition; the federal offer was withdrawn in 1974 with the introduction of the more comprehensive regional interconnections policy.

Nevertheless, Nova Scotia and New Brunswick continued their efforts at bilateral cooperation. In December 1976 a new 345 kV interconnection was installed; a transmission line with terminals at Salisbury, N.B. and Onslow, N.S. Initially this line was energized at a below-design voltage of 138 kV. In 1979 the voltage of the Salisbury - Onslow interconnection was raised to its design capacity. With three interconnections now in place, the total maximum design capability between New Brunswick and Nova Scotia is 600 MW.²⁰

The federal government provided loans to finance the last interconnection under its regional interconnections policy. Agreements were signed between Canada and New Brunswick on February 10, 1978, and between Canada and Nova Scotia on March 31, 1978, for these loans. Total loans to New Brunswick were \$10 million, representing 100 percent of its share of the estimated capital cost of the project. Total loans to Nova Scotia were \$2.6 million, representing 50 percent of its capital costs. The loan to New

Brunswick exceeded the 50 percent policy guideline because New Brunswick expected no benefit from the interconnection until 1981. In accordance with the terms of the agreement, New Brunswick repaid \$5 million plus accrued interest on April 1, 1981. The balance of this loan is subject to a 30-year repayment schedule, as is the Nova Scotia loan.

3.3.3 Fundy Tidal Power

The development of the Bay of Fundy tidal power resource has been studied sporadically since the early part of this century. For example, in 1915, the Cape Split Development Company of Nova Scotia investigated the exploitation of the energy potential of the Minas passage. Following this, a number of investigations of varying scope were carried out until the early 1960's, "none of which was sufficiently definitive to establish the merits of development; although they provided additional essential data."²¹

In the mid-1960's there was a revival of interest in the development of Fundy tidal power due, in part, to the implementation of the La Rance Tidal Power Plant in France. In August 1966, Canada, New Brunswick and Nova Scotia signed an agreement to study the prospects for large-scale development of Fundy tidal power. The agreement established the Atlantic Tidal Programming Board with membership from Canada and the two provinces.

The Board made its report in October, 1969.²² It concluded that, although three of the 23 sites studied had the best technical feasibility, none were economically viable under the prevailing rates of interest and costs relative to other energy sources.

In 1976-77 changes in energy economics due to escalating oil prices prompted the Bay of Fundy Tidal Power Review Board (which had been set up pursuant to an agreement of 1972 and composed of representatives from Canada, New Brunswick and Nova Scotia) to re-examine the prospects for Fundy tidal power.

²¹ TIDAL POWER IN CANADA - A REVIEW, R.H. Clark, P.Eng., May, 1987, p.31.

²² FEASIBILITY OF TIDAL POWER DEVELOPMENT IN THE BAY OF FUNDY, Atlantic Tidal Power Programming Board, October, 1969, p.20,21.

In its report, published in November, 1977,²³ the Board concluded that the economic feasibility of tidal power had been demonstrated but that the financial feasibility would depend upon direct governmental participation, due to the large minimum investment required of some \$3 billion. The report recommended further detailed investigations, including the development of definitive designs and consideration of the resolution of financial constraints. However, these recommendations were not acted upon.

In 1982, an economic, financial and technical update²⁴ of the 1977 study of the Cobquid Bay (B9) and Cumberland Basin (A8) sites was carried out, largely funded under the Canada-Nova Scotia Oil Substitution and Conservation Agreement, under the direction of Tidal Power Corporation (a Nova Scotia Crown Corporation).

The report indicated improved economic prospects for Fundy tidal power (including the latest technical improvements) provided that most of the output was exported to the United States. The report estimated that the B9 site, with an installed capacity of some 4800 MW, could be developed for \$20-\$25 billion and recommended that a detailed feasibility study of the B9 site be undertaken, including examination of staged development. This was not done.

In April 1984, a \$500,000 feasibility study was carried out by Alcan, under the direction of Tidal Power Corporation and funded under the Canada - Nova Scotia Oil Substitution and Conservation Agreement. The study included examining technical aspects which showed promise of allowing significant cost reductions, and updating costs for sites A8 and B9.

The study concluded²⁵ that further technical work should be a relatively low priority and that a second stage study should not be launched until further questions of marketing, retiming, and transmission questions were resolved, including means of retiming A8 energy at reasonable cost. Costs were estimated at \$2.56 billion for A8 (1428 MW) and \$7 billion for B9 (5338 MW) in 1984\$.

In August 1984, a 20 MW low-head tidal power project to demonstrate the straight flow (Straflo) turbine was officially placed in service at Annapolis Royal, Nova Scotia. The

23 REASSESSMENT OF FUNDY TIDAL POWER, Fundy Tidal Power Review Board, November 1977.

24 FUNDY TIDAL POWER UPDATE '82, Tidal Power Corporation, 1982.

25 FUNDY TIDAL POWER STAGE 1, Tidal Power Corporation, December 1985.

project was built for Tidal Power Corporation at a cost of some \$59 million, of which \$25 million was provided by Canada. This was the first tidal power project constructed in North America, and it successfully demonstrated the Straflo turbine for low-head tidal and hydro installations.

In spite of extensive study over the past quarter century, it has not so far proved possible to definitively establish the feasibility of developing the Fundy Tidal Power resource by resolving all questions of economics, environment, financial viability (in view of the high capital costs), and marketability (including the need for retiming the raw tidal energy).

3.3.4 Nelson River Transmission Initiatives

The Nelson River transmission system, which brings hydroelectric energy from generating stations on the Nelson River in northern Manitoba to load centres in southern Manitoba, is of course located entirely within that province. However, it is appropriate to discuss the development of Nelson River hydroelectric power in this section on bilateral initiatives for two reasons. First, this project was a cooperative effort of the federal government, Manitoba Hydro and the Manitoba government. Second, although contained in one province, this project linked two regions of that province, the north and the south. For this latter reason, the development of the Nelson River transmission system was certainly an interregional project, if not an interprovincial one. To illustrate the point that interregional interconnections need not be interprovincial, one of the goals of the Diefenbaker government's National Power Policy was the interconnection of hydro resources in northern Canada with southern load centres, and the 1974 regional interconnections policy provided for financing for transmission links between distinct regions of a province.

In the early 1960's Manitoba faced a choice between developing thermal generation in the south or hydroelectric potential in the north in order to meet future load demand. Hydro development in the north would be more economic over the long term but it involved greater financial and technological risks. The financial risk was greater because a much larger initial capital investment would be required than if thermal generation were expanded. The technological risk stemmed largely from the need to employ a high voltage direct current (HVDC) transmission system to deliver the power over hundreds of kilometres. This technology is more efficient than alternating current technology for long distance transmission, but was still in its infancy in the mid-1960's.

The federal government participated, along with Manitoba Hydro and the provincial government, in a research and development program in HVDC transmission in order to ensure that the technology was suitable for Manitoba's needs. Pioneering research in HVDC technology was done. In 1966 Canada and Manitoba signed an agreement under which Canada designed, built and financed the 880 km HVDC transmission system. When completed, this system had the highest voltage and covered the longest distance of any HVDC transmission system in the world. The transmission system was built by Atomic Energy of Canada Limited (AECL) and was declared in operation in 1973.

Once the HVDC system was completed, the debt that Canada had incurred was transferred to Manitoba Hydro, which agreed to repay the loan over a 45-year period. The loan will be fully repaid by the year 2019 at a fixed rate of interest of 5 5/8 percent. At about the same time that the original transmission line was completed, however, Manitoba began planning for additional generating capacity on the Nelson River to supply the province's growing electricity demand and in order to be able to take advantage of export opportunities. Manitoba's plans necessitated the upgrading of the capacity of the HVDC system to carry the additional output.

In 1977 Canada and Manitoba signed a new agreement for the expansion of the HVDC transmission system. Canada agreed to provide loans, up to a maximum of \$193.2 million, for 50 percent of the cost of expanding the system. Currently, the HVDC line connects generation in the area of Gillam on the Nelson River, with Winnipeg at voltages of ± 450 kV DC and ± 500 kV DC.

3.3.5 Newfoundland (Labrador) - Québec Initiatives

The story of the development of hydroelectric power in Labrador is in some ways an allegory for efforts at interprovincial and interregional cooperation everywhere in the country. A rich natural resource of hydroelectric potential attracts the eye of the developer, and the benefits to be obtained from its development seem obvious. However, in Labrador as in so many other regions of the country, a cooperative effort by two provinces is necessary in order to achieve the full benefits of development. It is in the making of specific arrangements for such cooperation and for the sharing of benefits that problems arise which serve to prevent the full potential of a development opportunity from being realized.

Labrador contains a number of rivers suitable for hydroelectric development, the Churchill River chief among them. This potential was recognized by the Government of Newfoundland and Labrador in the early 1950's; Newfoundland's Lease Acts of 1953 and 1961 gave hydroelectric development rights on the Upper Hamilton River (renamed Churchill River in 1965) to a British-led consortium named Brinco, through its subsidiary, the Hamilton Falls Power Corporation (HFPC). HFPC would later be renamed Churchill Falls (Labrador) Corporation (CFLCo).

HFPC constructed a 225 MW generating station at Twin Falls on the Upper Churchill River in 1960. This power was to be used in Labrador. However, it was evident that future generating stations would have a much larger capacity, far beyond the demand in Labrador or on the Island of Newfoundland. In order to make development of the Churchill Falls project feasible, a long-term market for the sale of firm power was needed. Brinco initiated negotiations with Québec, Ontario and U.S. utilities. Ontario was not interested. US utilities were more interested, however any sales to the US would have necessitated the cooperation of Québec in wheeling the power through its system, and Québec was opposed to providing this service. As a consequence, the only market for Churchill Falls power was Québec which at that time foresaw a need for additional capacity to meet its growing domestic demand.

Brinco entered into negotiations with Hydro-Québec for the sale of Churchill Falls power and its transmission to load centres in Québec. A letter of intent was signed by the two parties on October 31, 1966, in which they intimated their intention to enter into a contract for the development of Churchill Falls power. The federal government had a role in the negotiations; it lobbied Québec in order to persuade the province to collaborate with Newfoundland on the Churchill Falls project before developing its own hydroelectric mega-projects with comparable economics. Continued negotiations resulted in the signing of a power contract between Brinco's subsidiary CFLCo and Hydro-Québec on May 12, 1969, made possible by Hydro-Québec's assumption of financial responsibilities. CFLCo agreed to sell, and Hydro-Québec agreed to buy, specified amounts of firm power under the prices, terms and conditions set out in the contract.

A few of the contract's more important provisions can be paraphrased here. One clause stipulates that the power contract is governed by and interpreted in accordance with the

laws of Québec, and any disputes associated with it are to be decided by the Superior Court of Québec, District of Montréal. At the time the contract was signed, it was expected that all generation and transmission facilities would not be constructed until September 1, 1976, the Effective Date. Any power produced before that date would be bought by Hydro-Québec. The term of the contract is forty years from the Effective Date, with a renewal for another twenty-five years on a basis stated in the contract. Therefore, Hydro-Québec and CFLCo have mutual obligations respecting Churchill Falls power until 2041.

CFLCo's firm capacity commitment to Hydro-Québec amounts to about 90 percent of Churchill Falls' output; the station has a generating capacity of 5429 MW.²⁶ The price provisions of the power contract have caused much controversy. There is a fixed price formula in the contract which provides that the price payable by Hydro-Québec will gradually decline from almost 3 mills/kW.h at the Effective Date to 2.54 mills/kW.h in 2016. From 2016 to 2041, Hydro-Québec shall pay CFLCo 2 mills/kW.h for continuous energy.²⁷ CFLCo retains the rights to the 225 MW of power from Twin Falls. Moreover, the power contract gives CFLCo the right to recall 300 MW of the power committed to Hydro-Québec on giving three years' advance notice.

Construction of the Churchill Falls project was begun by Brinco in 1966 and finished in 1974, two years ahead of schedule. CFLCo's financing came from Brinco (58 percent), Hydro-Québec (34 percent), and Newfoundland (8 percent); the Government of Newfoundland and Labrador bought out Brinco in 1974, with the result that its utility, Newfoundland and Labrador Hydro, now owns 66 percent of CFLCo. The total cost of the construction of the Churchill Falls generating station and three 735 kV transmission lines from the station to the Québec border was \$946 million. Hydro-Québec built three new 735 kV transmission lines from the Labrador border to its power grid at a cost of \$400 million. Furthermore, Hydro-Québec provided additional debt financing, and project-completion and debt-servicing guarantees.

Since 1976 the Churchill Falls development has had a long and checkered history, which will not be detailed here. A dispute between Newfoundland and Québec arose over the

26 ELECTRIC POWER IN CANADA 1988, p.24.

27 The terms and conditions that will be in force during the renewal period (2016 to 2041) are set out in Schedule III of the Power Contract. Any articles or sections of the Contract not specifically contained in Schedule III "shall have no force or effect beyond the expiry date [2016]".

sharing of the benefits provided by Churchill Falls. The dispute surfaced in 1976 with Newfoundland's initiative to recall 800 MW of power from Churchill Falls over and above the recall provision of the power contract with Hydro-Québec. Newfoundland's position is that it receives less than a fair share of the benefits from Churchill Falls under the 1969 power contract, and that the contract must be changed to reapportion the benefits. Québec's position is that as it took most of the financial risks involved in the project, Churchill Falls would never have been developed had the contract's terms originally been less favourable to it. Suffice it to say that this dispute has not been resolved. It should be emphasized, however, that the Québec-Newfoundland dispute is over the sharing of the benefits from Churchill Falls; it is not disputed that Churchill Falls was a worthwhile development. Unfortunately, the effect of the dispute has been to prevent subsequent development of other Labrador hydroelectric sites.

3.3.6 Lower Churchill Development Corporation

A bilateral initiative between Canada and Newfoundland began in 1978; the Lower Churchill Development Corporation (LCDC) was formed in order to develop hydroelectric sites on the Lower Churchill River. The LCDC is owned 51 percent by Newfoundland and 49 percent by Canada; it was agreed that the two participants would provide equity for LCDC projects in those proportions.²⁸ The LCDC was formed "with the primary objective of establishing a basis for the development of all or part of the hydroelectric potential of the Lower Churchill Basin"²⁹ and to supply power to the Island of Newfoundland.

The LCDC conducted a study of the feasibility of developing hydroelectric sites at Gull Island and at Muskrat Falls. The recommendations of the study were presented to the shareholders in June 1980. The study found that the Gull Island site, with a potential of 1698 MW, would be the most economic to develop. However, there was no market in Labrador or on the Island for all of its output. Therefore, Gull Island could be developed only if its surplus power could be sold to or through Québec at a price of about 30 mills/kW.h.³⁰ The study recognized that such a sale was not likely and that the energy demand of Newfoundland and Labrador Hydro was the only firm marketing opportunity

28 See Clause 4.3 of the Agreement of 24 November 1978 between Canada and Newfoundland.

29 See the Agreement of 24 November 1978 between Canada and Newfoundland.

30 PRESENTATION TO THE SHAREHOLDERS OF LOWER CHURCHILL DEVELOPMENT CORPORATION LIMITED, PROJECT RECOMMENDATION, vol. I, Executive Summary, p.20.

available to the LCDC. Therefore, the study recommended that the less economic 618 MW Muskrat Falls site be developed and that transmission facilities be constructed to interconnect Labrador with the Island of Newfoundland.³¹ It was contemplated that a ± 400 kV High Voltage Direct Current transmission system would be used, on an 800 MW bipole circuit. An 18 km submarine cable transmission system would be constructed across the Strait of Belle Isle, using four ± 400 kV cables laid in two seabed trenches.³² In the end, the LCDC recommendation to develop Muskrat Falls was never followed. By 1981 the Newfoundland government had decided that its best option was to pursue further negotiations with Québec for the recall of 800 MW of Churchill Falls power. Newfoundland attempted to enlist the federal government in aid of its cause with Québec, and it dropped consideration of the Muskrat Falls development.

3.3.7 New Brunswick - Québec Initiatives

New Brunswick and Québec have a long history of bilateral cooperation. These two provinces provide what is perhaps the best proof that interprovincial electricity projects will be developed when both provinces see that it is to their mutual advantage to do so. Several interconnections have been built between New Brunswick and Québec.

Discussions between NB Power and Hydro-Québec regarding the interconnection of their systems began in the early 1960's, but it was not until 1965 that the first interconnection was placed in service, a 69 kV standby interconnection. Prior to this the utilities had made border accommodation agreements. Joint studies on the feasibility of greater interconnections were then undertaken. These studies led, in December 1968, to the completion of a 138 kV synchronous tie connecting NB Power's Eel River terminal with Hydro-Québec's Matapédia terminal.

The cooperation between the two utilities at that time arose out of the coincidence of their respective needs. Hydro-Québec was expecting to have energy surpluses for several years in the early 1970's as a result of the commencement of operations at the Churchill Falls hydroelectric generating station in Labrador. Hydro-Québec would receive virtually all of Churchill Falls' output. On the other hand, NB Power was interested in

31 Ibid., p.23.

32 PRESENTATION TO THE SHAREHOLDERS OF LOWER CHURCHILL DEVELOPMENT CORPORATION LIMITED, PROJECT RECOMMENDATION, vol.II, p.54.

purchasing some of this power, in order to be able to defer its requirement for additional thermal generating capacity in New Brunswick.

Federal assistance was sought to build a new interconnection which would enable such a sale of power to take place. In December 1968, Cabinet approved the provision of a \$4 million grant to New Brunswick toward the cost of the \$25 million Eel River N.B. back-to-back ± 80 kV DC converter station. This station has a capacity of 320 MW. The federal grant was made available through the auspices of the Department of Regional Economic Expansion and the APPDA. The grant was made conditional upon: (i) no future agreements being entered into with New Brunswick Power under the APPDA; and (ii) agreements being made between the Québec, New Brunswick and Nova Scotia utilities to expedite regional coordination of the planning and operation of the interconnected systems, with Prince Edward Island to be included at the earliest possible time.

In March 1969, Hydro-Québec and NB Power signed a letter of intent whereby Hydro-Québec undertook to deliver energy to NB Power for a period of five years, commencing in 1971. The Eel River converter station was constructed, and began operating on 28 July 1972. In order to be able to deliver the power to Eel River, Hydro-Québec built a double circuit 315 kV transmission line from Rimouski to Matapédia. Two 230 kV lines were built to connect Matapédia to Eel River.

In 1981 Hydro-Québec and NB Power began discussing the possibility of a major new interconnection between their systems. The new tie was completed in three phases. In April 1983 a temporary 138 kV radial feed was energized, providing 50 MW of power to customers in northwestern New Brunswick directly from Hydro-Québec's system. In 1984 this radial connection was upgraded to 315 kV, increasing the design capability to 300 MW. In 1985 Hydro-Québec completed a ± 80 kV DC back-to-back converter station at Madawaska, with a capacity of 350 MW. This converter station was then connected to NB Power's Edmundston terminal by a 345 kV transmission line.

At present, the total design capability of the New Brunswick - Québec interconnections is 1050 MW. The primary interconnections, the asynchronous DC ties at Eel River and Edmundston, each have a capability of 375 MW and allow energy to be transferred

between the two systems. The radial connection between Québec and isolated loads in northwestern New Brunswick provides the remaining 300 MW of capability.³³

3.3.8 New Brunswick - Prince Edward Island Initiatives

Prince Edward Island's small and isolated electric system has gained much from its interconnection with New Brunswick. Since the early 1960's, New Brunswick and Prince Edward Island have engaged in studies of the feasibility of a submarine cable connecting the Island to New Brunswick. P.E.I.'s oil-fired generating system faced rapidly escalating fuel costs in the mid-1970s; this motivated the Island's utility, Maritime Electric Company Limited (MECL), and the provincial government to come to an agreement with New Brunswick for the construction of a submarine cable and the purchase of power. The purpose of this interconnection was to reduce oil consumption and electrical energy costs on P.E.I. by enabling delivery of lower cost non-oil-fired power from New Brunswick.

In October 1976 an interconnection agreement was signed between New Brunswick and Prince Edward Island. It was expected at that time that P.E.I. would participate in New Brunswick's Point Lepreau nuclear station; there were negotiations to that end undertaken between MECL and NB Power. NB Power's view was that participation in Point Lepreau was one of the main motivations behind the construction of the submarine cable: "It [the cable] will extend to P.E.I. the normal benefits of an interconnected operation and ensure the opportunity for the purchase of 5 percent of the output from the first Point Lepreau nuclear unit in New Brunswick."³⁴

In the end, P.E.I. did not participate in the Point Lepreau project.³⁵ However, two 22 km submarine cables were ploughed into the seabed of the Northumberland Strait. Each cable contains a three-core 138 kV transmission line and has a design capability of 100 MW. The cables can be converted to ± 200 kV DC operation if so desired.³⁶ The cables were commissioned on October 28, 1977. In 1988 P.E.I. received 87 per cent of

33 Ibid.

34 NB Power, 1976 Annual Report, p.10.

35 The story behind P.E.I.'s decision not to participate in Point Lepreau is told in the Maritime Energy Corporation segment of Section 3.2.3.

36 Maritime Electric Company, Limited, Annual Report 1977, p.3.

its electricity through the cables³⁷; before 1977 P.E.I. was 100 per cent dependent on imported oil for electricity generation.

The federal government supported the submarine cable initiative. Financial assistance was provided under the regional interconnections policy. Pursuant to an agreement signed on October 6, 1977, between Canada and P.E.I., a DREE grant of \$18 million and a \$9 million Energy, Mines and Resources loan were made to P.E.I. to help defray the estimated total capital cost of \$36 million. Normally, a loan under the provisions of the regional interconnections policy would provide 50 percent of the project's capital cost. However, in view of P.E.I.'s limited financial capability, the DREE grant was also made. Originally the loan was to be repaid over a 30-year period from 1978 to 2008, but the loan was extinguished under the terms of a subsequent agreement of March 31, 1985.

The submarine cable initiative is not the only example of cooperation between New Brunswick and Prince Edward Island. In August 1981, MECL signed an ownership participation agreement with NB Power for a 10 percent share of Unit 2 of the coal and oil-fired Dalhousie generating station. "This partial ownership of a generating facility by a utility of a neighbouring province is a Canadian first."³⁸ The 20 MW of power that P.E.I. receives from its share of Dalhousie represents about 15 per cent of P.E.I.'s demand.³⁹

3.3.9 Alberta-British Columbia Initiatives

The Alberta Interconnected System is an umbrella organization of the Alberta electric utilities. "Prior to 1986, the Alberta Interconnected System (AIS) was, for all intents and purposes, an electrical island."⁴⁰ The Alberta utilities had to rely on their own installed reserve generating capacity to ensure a reliable supply of electricity. The Alberta utilities' reserve capacity was generally about 22 to 25 percent of peak load.⁴¹

Since 1973, TransAlta Utilities Corporation of Alberta has had a 138 kV interconnection with B.C. Hydro at Natal.⁴² However, the limited capacity of the Natal interconnection

37 ELECTRIC POWER IN CANADA 1988,p.19.including 20 MW output from the jointly owned Dalhousie plant in N.B.

38 NB Power, 1982 Annual Report,p.5.

39 ELECTRIC POWER IN CANADA 1988,p.21.

40 Electric Utility Planning Council, AIS RELIANCE ON EXTERNAL INTERCONNECTIONS, June 22, 1989,p.2.

41 Ibid.

42 ELECTRIC POWER IN CANADA 1988,p.95.

did not allow for the deferral of generation in Alberta. Moreover, operating experience indicated that the Natal interconnection was not a reliable source of supply, as the interconnection often tripped during contingency situations. A larger, more reliable interconnection was needed.

In 1982, B.C. Hydro and TransAlta Utilities agreed to establish an interconnection that would allow each provincial system to rely on the other for 300 MW of power. A 500 kV interconnection between TransAlta Utilities and B.C. Hydro was commissioned in January, 1986. The transfer capability of this interconnection is 1000 MW to B.C. Hydro and 1200 MW to TransAlta⁴³, but the reciprocity agreement necessitates that it be operated at 300 MW. The primary reason that these utilities built this interconnection is that it allows them to reduce their own generation requirements by relying on each other for support. A reliability analysis of the AIS indicated that Alberta can defer about 400 MW of generation capacity and still meet its obligation to British Columbia, with this interconnection in place.⁴⁴ British Columbia will also be able to reduce its in-province reserve generation capacity as a result of this interconnection. Alberta now has indirect access to the U.S. market, and British Columbia has another market for its power through this interconnection.

More recently, the AIS and B.C. Hydro participated in a joint study in order to determine what benefits might be obtained from coordination of the operation and construction of generation facilities.⁴⁵ The potential benefits arise from the different nature of the two systems: B.C. Hydro relies primarily on hydroelectric generation while the AIS relies primarily on thermal generation. The study suggested four possible degrees of coordination that could be achieved and described the benefits available from each. The study concluded that between \$600 million and \$1.2 billion in generation costs could be saved over the period 1990-2010, depending on the nature of construction coordination.⁴⁶

43 Communication from TransAlta, August 6, 1991.

44 AIS RELIANCE ON EXTERNAL INTERCONNECTIONS, p.3.

45 B.C. Hydro - Alberta Interconnected System Generation Coordination Study, March 22, 1989.

46 Ibid, p.2.

3.3.10 Alberta - Saskatchewan Initiatives

Alberta has also been involved in a recent bilateral initiative with Saskatchewan. In November, 1989 a 230 kV interconnection with 150 MW capacity came into service between the two provinces. This line runs from Swift Current, Saskatchewan to Empress, Alberta, and is the final link between the mainland power systems of Canada. This interconnection required a back-to-back DC converter station as it connected two asynchronous systems. Alberta Power Limited and SaskPower combined efforts to build this line at a cost of \$41 million.

Through this interconnection, SaskPower relies on a reserve capacity of 150 MW from the Alberta utilities. A reserve capacity of 125 MW will be available to Alberta utilities through this line beginning in 1995. Alberta Power Limited has enumerated several benefits to Alberta which it believes are provided by its interconnection with SaskPower: (i) it provides an additional source for purchases of energy; (ii) it enhances the bargaining position of the AIS vis-à-vis B.C.; (iii) it enhances the flexibility of the transmission system in southern Alberta; and (iv) it allows for the possible deferral of additional capacity in Alberta.⁴⁷

3.4 Conclusions

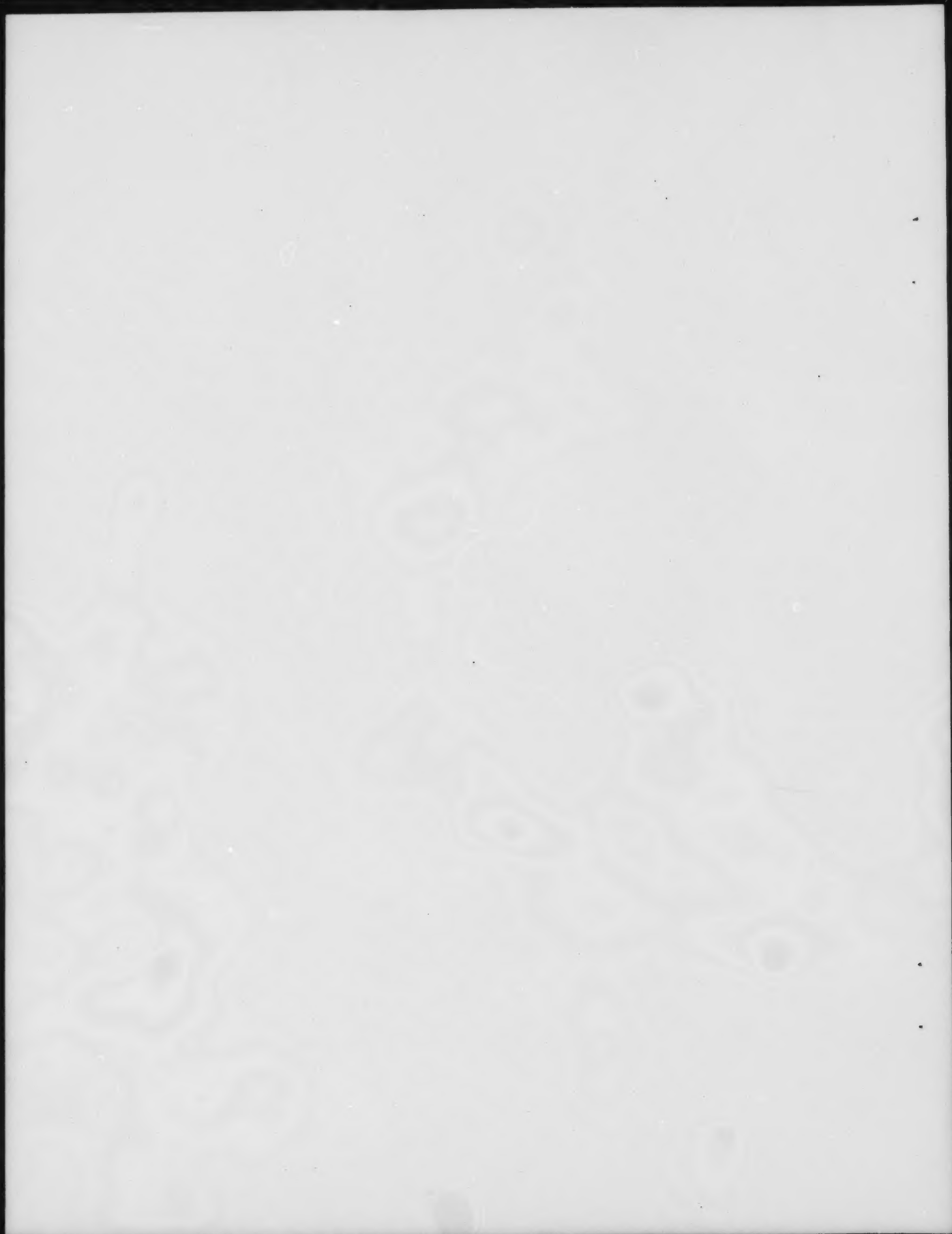
It is evident from the above discussion that utilities in all regions of the country are, in general, willing to participate in profitable interprovincial cooperative projects. However when such arrangements require the provision of wheeling services to other parties, agreements have been difficult to achieve. Bilateral initiatives have succeeded where the provinces saw clear benefits which outweighed the risks of participation. Of equal importance is the requirement that the provinces feel that the benefits of a joint project are shared equitably over its life; this is an essential ingredient of a continued climate of cooperation. The success of bilateral initiatives has some lessons for those who wish to promote further interprovincial activity. Perhaps bilateral initiatives have succeeded when national or regional initiatives have failed because the bilateral initiatives involved a narrower range of activities and offered a clearly defined method of sharing risks and benefits. Also, it is worth noting that no bilateral initiative has involved the creation of a

47

Public Utilities Board, Alberta, Decision E89004, Re: Alberta Power Ltd., Edmonton Power, TransAlta Utilities Corporation, February 15, 1989, p.39.

decision-making institution other than the provinces themselves. One likely reason for the willingness of provinces to enter bilateral initiatives is that they do not fear a loss of autonomy. The challenge for those who design measures to increase interprovincial utility activity will be to create mechanisms that are effective at realizing economic gains without losing the trust of the utilities and the provinces.

4. THE NATURE AND BENEFITS OF INTER-UTILITY COOPERATION



4. THE NATURE AND BENEFITS OF INTER-UTILITY COOPERATION

4.1 Introduction

Inter-utility cooperation in electricity trade is a vast subject, embracing a great many diverse activities and functions. The purpose of this chapter is to describe some of the main aspects of the subject and to outline the benefits and constraints associated with the various categories and sub-categories of cooperation.

4.2 Dimensions of Inter-utility Cooperation

There are two major difficulties that complicate any attempt to describe how utilities cooperate with one another. The first concerns terminology. Words and phrases used in a certain way by one group of utilities may be used somewhat differently by another group of utilities; there is hence no single "correct" terminology that can be employed in describing inter-utility cooperation. To circumvent this difficulty in the discussion that follows, the most important concepts have been defined as precisely as necessary given the context; thereafter, an effort has been made to use them consistently, even though this may lead to some artificiality in certain cases.

The second difficulty is that there are many different dimensions to inter-utility cooperation. That is, any particular cooperative arrangement can be described in terms of the basic purposes being served, the particular services being offered, the financial parameters, the length of the contract, whether or not wheeling is involved, and so forth. At least eight of these dimensions can be discerned:

- (1) Inter-utility cooperative arrangements are put in place for several *purposes*, for example to improve the reliability of the cooperating systems or to achieve certain economic benefits.
- (2) The arrangements fall into two principal *functional categories* (operations and planning), within which there are numerous functional sub-categories.
- (3) The arrangements can be bilateral or multilateral, the distinction being important because the latter involves *wheeling*.

- (4) The cooperation can take place through a variety of formal or informal mechanisms, ranging from informal deal making to various kinds of pooling arrangements.
- (5) The cooperative arrangements can be for different periods of *time*.
- (6) They can involve different *economic terms and conditions*.
- (7) They can have important *environmental implications*.
- (8) They can vary widely in *geographical extent*.

Each of these eight dimensions is discussed in the sections that follow. Before proceeding, however, it is worth noting that while the analysis of inter-utility cooperation using the framework of dimensions and sub-dimensions is useful for descriptive purposes, electrical utilities generally do not think about cooperation in this abstract way. This is because, in reality, the various dimensions are inextricably linked. Chapter 1 of this report describes the evolution of the Canadian interconnected system. This evolution can help illustrate the linkage among the dimensions of inter-utility cooperation.

Canada's electric utilities generally started out as isolated systems serving local customers. Cooperation began when they first entered into bilateral interconnection agreements with their immediate in-province neighbours. Intraprovincial cooperation then continued through corporate mergers, the establishment of provincial Crown corporations, and the evolution of formal and informal pooling mechanisms between separate utilities. In tandem with the extension of intraprovincial cooperation, interprovincial and international cooperation proceeded as well, through a series of bilateral arrangements that led to the emergence of a few large interconnections spanning the continent as a whole. Simultaneously, the growing interdependence of the interconnected systems led to increasingly formal mechanisms to define and regulate common reliability criteria. As the Canadian grid evolves, further cooperative arrangements - intraprovincially, interprovincially and internationally - are likely. (For a fuller treatment of the evolution of the Canadian electricity supply industry, see Chapter 1.)

4.3 Purposes of Inter-utility Cooperation

Electric utilities cooperate with one another for many purposes. For example, they cooperate in a variety of information-sharing programs, the provision of emergency support (including facilities and repair crews), and in the management of research and development. They also work together extensively to develop the reliability criteria that govern the planning and operation of their interconnected systems, and they plan and operate their systems cooperatively so as to ensure that these criteria are satisfied. Utilities may also cooperate: (i) to optimize the development and utilization of resources taking account of such factors as financial costs, environmental and socioeconomic impacts, and security of supply; (ii) to maximize opportunities for interprovincial and international exports; and (iii) to achieve the economies associated with large-scale generating units. These latter three goals may be characterized, generically, as "economy" objectives.

It is interesting to note that, while the electricity supply industry tends to differentiate between cooperation for "reliability" purposes and cooperation for "economy" purposes, in reality the two are inseparable. Conceptually, reliability is embedded within the idea of service, and it is reliable service that utilities seek to provide to their customers at the lowest reasonable cost. Strictly speaking, therefore, reliability cannot be divorced from economy; nevertheless, the distinction is a useful one to maintain, because the kinds of cooperation that take place under the aegis of the North American Electric Reliability Council (NERC) are ones that all member utilities voluntarily adhere to for mutual support and assistance, whereas the various economy arrangements tend to be more discretionary.

This study was not concerned with the extensive and specific kinds of inter-utility cooperation that have evolved (and which continue to evolve) within NERC to address issues of reliability. Its focus was rather on the way that cooperation can serve and enhance other objectives.

4.4 The Functional Dimension

Function is the second dimension of inter-utility cooperation and is concerned with what utilities actually *do* when they agree to cooperate for a certain purpose. Utilities perform two basic functions: operations and planning. Operations are concerned with optimizing

the use of a fixed set of facilities to meet current requirements. Planning is concerned with optimizing the system to meet future needs.

A group of utilities can coordinate their operational functions and integrate their planning functions in a great variety of ways, and a number of these are described below. The examples given are illustrative rather than comprehensive. However, because the functional dimension is critical to clarifying the scope of this study, enough detail has been given to identify the kinds of cooperation that are of most interest.

4.4.1 Operational Arrangements

Isolated utilities have no alternative but to meet their load requirements by planning and operating their systems in the most economic way possible on a self-sufficient basis. On the other hand, when two or more systems are interconnected, each one potentially has access to a greater number of generating units. This permits the interconnected systems to engage in a variety of mutually beneficial arrangements to the extent that transmission constraints permit. There is a multiplicity of such arrangements, which are typically defined in interconnection agreements and which depend upon the state of the two power networks at any given point in time. Some of the more common ones are described below.

Economy Energy

Economy energy is energy that may be delivered in order to effect savings in generation costs when the receiving party already has sufficient capacity and energy to supply its own system demand, including exports. Economy energy from the supplying system is used to displace energy that could otherwise be produced by the receiving system, but at a higher incremental cost. For example, a hydro system that has water in its reservoirs in excess of what it anticipates needing could sell energy to a neighbouring thermal system, displacing fuel that would otherwise have to be burned. Economy energy is generally scheduled hour by hour, subject to transmission constraints, and it is interruptible at any time upon notice. Sufficient notice is given to enable the receiving party to start up generating units of its own.

Economy energy may be divided into various sub-categories. For example, hydro systems sometimes distinguish between "secondary energy", which can be stored and

sold at the time of maximum economic value - and "spill energy", which must be sold immediately because reservoirs are filled to capacity. Other distinctions depend on whether the source of the energy supplied is a renewable resource (e.g. hydro) or a non-renewable resource (e.g. coal). In general, different price formulae apply to each of these various sub-categories. Some utilities use the term "economy energy" when thermal energy is used to displace another, more expensive, form of thermal generation, and the term "fuel displacement" when renewable energy (e.g. hydro) displaces thermal generation.

Non-Economy Capacity And Energy

Economy energy is generally scheduled hour to hour. Capacity and energy can also be contracted for longer periods ranging from weeks to more than a year. Such capacity and energy are surplus to the requirements and commitments of the seller, and are used by the buyer to improve the economy and reliability of its system. The types of such longer-term arrangements vary:

- *Scheduled outage capacity and energy* are supplied during a period when the receiving party is experiencing a scheduled outage.
- *Participation capacity and energy* is capacity and associated energy that is continuously available from one or more specific generating units (except when such units are temporarily out of service).
- *System capacity and energy* is continuously available from the supplier's system as a whole.
- *Peaking capacity and energy* is capacity and associated energy sold on the expectation that it will be used at a low capacity factor i.e. that it will be called upon only at peak periods.
- *Supplemental energy* is provided to supplement the off-peak generating capability of the receiving party during periods of prolonged energy deficiency. It could be purchased by a hydro system during low water years or by a thermal system during a period when offshore fuel supplies are unavailable.

- *Emergency capacity and energy* is supplied when a system is unable to meet its load as a result of a forced outage. The "emergency" period is usually limited in time by the terms of the interconnection agreement; if an outage extends beyond the agreed upon emergency period, other categories of capacity and energy would be made available if needed.
- *Environmental capacity and energy* is supplied in order to assist the receiving system to meet its environmental requirements (e.g. emissions limits on a thermal system may be met by imports from a hydro system).

Management Of Operating Reserves

Utilities maintain operating reserves in order to be able to respond to various contingencies (i.e. losses of major elements of supply). There are several categories of operating reserves. "Ten-minute reserves" must be fully available within ten minutes, and are designed to meet a first contingency. Ten-minute reserves comprise the following: unloaded capacity synchronously connected to the supplier's system ("spinning" reserves), units that can be started and loaded within ten minutes, and load reductions that can be made within ten minutes. "Thirty-minute reserves" are additional operating reserves that can be made available within thirty minutes, and are generally held to protect against a second contingency. System operators manage their operating reserves by having regard to the size of their anticipated load, the availability of different kinds of generating units on their own system, transmission bottlenecks, and the capability of their interconnections. The existence of the latter means that cooperating utilities can effect mutual savings in the management of their operating reserves because the consequence of a forced generation outage is an instantaneous increase in energy flows across the ties. In effect, the interconnection acts as a reserve generator.

Maintenance Scheduling

Related to the problem of managing operating reserves is the question of scheduling generating units and transmission lines for maintenance. Two of the key variables that a system operator must consider in preparing for contingencies are the units available for service and the state of the transmission network. Maintenance carried out on a coordinated basis by a group of utilities can reduce costs and enhance reliability because

the use of inefficient facilities and/or the introduction of temporary reserve reductions can be minimized or eliminated.

Load Frequency Control

In the minute-to-minute operation of a power system, generation must be matched to total load to maintain the frequency of the system and to ensure that actual tie-line flows track as closely as possible the flows scheduled. This task is carried out automatically by the Automatic Generation Control ("AGC") system which, through feedback control mechanisms, automatically changes the generation at certain generating plants (regulating plants) to maintain frequencies and tie-line flows at the desired levels. Interconnected utilities can perform the AGC tasks individually or in an integrated manner. When one of the utilities does not have enough regulating units or when its AGC system is not functioning, it can contract with other interconnected utilities to provide this service.

Economic Dispatch

In order to ensure least cost operation in meeting combined system demands, generators on interconnected systems are brought on line (dispatched) according to their incremental costs; units with the lowest incremental costs are dispatched first.

4.4.2 Planning Arrangements

An electric utility must ensure: (i) that the total generating capacity on its system plus capacity contracted from other systems is adequate to meet its system peak load plus outside firm commitments, with sufficient reserve margin to enable maintenance to occur, to deal with forced outages of generating units and, in some cases, to allow for load growth uncertainties; (ii) that dependable system energy plus contracted energy is adequate to supply system firm energy demand and outside firm commitments; (iii) that its opportunities for buying, selling, and exchanging capacity and energy in external markets have been optimized; and (iv) that the transmission system is adequate to meet the system load reliably.

In considering these objectives, system planners assess a number of factors, including capital costs, social and environmental constraints, the likely future availability and cost

of fuel, financial and regulatory risks, and the extent to which the mix of generation is balanced with respect to the size, number, type and location of the various units on the system. When a group of utilities agree to integrate their planning functions, the range of options available can expand significantly to the mutual benefit of all the cooperating parties. The principal ways in which planning functions can be integrated are discussed below.

Purchase And Sales Agreements

Perhaps the simplest type of cooperation at the planning level comes about when two utilities agree to enter into a specific purchase/sales agreement. Such agreements fall into at least two different classes: (i) near-term supply-demand balancing; and (ii) long-term purchases.

Because the time between the decision to build a new facility and the date of it coming into operation can be quite long, and because load growth is so uncertain, utilities must continually reassess their *near-term supply-demand balances*. ("Near term" here refers to the period after facility commitments have been made but before the new units come into production.) The objective is always to maintain sufficient reserve margins for system reliability purposes while at the same time minimizing total costs. Opportunities for cooperation in supply-demand balancing arise because, even when commitments to build new facilities have been made, there is flexibility to temporarily defer construction when short-term excess capacity exists on neighboring systems. Alternatively, when load growth is unexpectedly strong, cooperation may be necessary to maintain adequate reserve margins. On the supply side of the equation, sales agreements provide revenue from the excess capacity and energy that sometimes exist when large new facilities first come into operation.

Interconnected utilities, when planning to meet their long-term load requirements, have the option to either build new capacity or buy power from elsewhere. Most choose to build. However, circumstances do arise for utilities to minimize costs by entering into *long-term firm capacity/energy purchase agreements*. Such purchases may not be unit specific; the seller basically contracts to supply energy and/or capacity that is then made available from its system as a whole. In such a case, the seller is responsible for providing the necessary generation reserves.

Generation Planning

Utilities can integrate their generation planning functions in a number of ways, depending on the characteristics of their respective systems and the extent to which they are prepared to become reliant on generating resources outside of their own franchise areas. At the simplest level, two or more utilities can agree to share reserves. Certain more specialized cooperative arrangements become possible if the systems share a common river system, if they are able to take advantage of hydro/thermal or hydro/tidal synergy, or if there is diversity in the times that they experience peak loads. More generally, two or more utilities can fully integrate their generation planning functions by agreeing to develop new facilities according to objective criteria i.e. without regard to any parochial considerations of where the needed facilities are located. These arrangements are summarized in more detail in the paragraphs that follow.

Reserve sharing is possible no matter what kind of generating capability the interconnected systems have. Utilities maintain reserves in order to enable maintenance to occur, and to deal with forced outages of major generating units. Interconnections allow utilities to share their generation reserves, thus reducing the amount of total reserve that the combined systems must carry. At the planning stage, utilities are able to decide the size and mix of reserves that would be optimal over the long term. In general, the reserve sharing benefits are inversely proportional to the relative size of the cooperating systems. Smaller systems tend to receive relatively more reserve benefits than do larger ones.

Hydro/hydro synergy arises when there are benefits from the joint management of a shared river system. For example, situations may occur where one of the utilities does not have the reservoir capacity to store all of the water available to it at a given point in time. If the rivers in question can be regulated by storage facilities developed on the neighbouring system, opportunities for cooperation are possible. The objective is to manage flows and storage in such a way as to maximize benefits to the combined systems.

Hydro/thermal synergy becomes possible when a predominantly hydro system is contiguous with a predominantly thermal system. Hydro-based systems with limited reservoir capacity tend to have energy as the critical criterion to be met in the planning of new facilities. Thermally-based systems, on the other hand, are generally capable of

producing more energy than they need; for them, capacity is the critical planning criterion. Interconnection of hydro and thermal systems thus provides considerable opportunities for mutual benefits. For example, energy reserve agreements can increase the amount of firm energy that hydro systems can schedule, thereby allowing them to defer new capacity that would otherwise be required or, alternatively, to engage in joint export arrangements involving electric power of higher quality and quantity. At the same time, thermal systems can rely on hydro systems for peaking requirements, and they may also be able to share in the benefits associated with new hydro sites that can be developed at costs lower than thermal alternatives.

The possibility of *hydro/tidal* synergy arises because of the fact that the times at which tidal systems can deliver large amounts of electrical energy do not generally correspond to the times when such energy is needed. This energy can be "retimed" by being stored for use when needed in a hydro system having excess storage capacity.

Seasonal or Time diversity arrangements become possible when different utilities determine that their respective peak demand periods come at different times. There are at least three reasons why this kind of diversity might arise. The first is that periods of peak electricity demand are determined by the weather and a host of other variables; statistically, therefore, the time of peak demand will vary from one area to the next. The second reason is that different time zones will result in some east-west diversity in peak periods. The third reason is north-south seasonal diversity: utilities in the north tend to have their peaks in the winter, while those in the south have summer peaks. This fact - that the period of peak demand for one utility is generally not coincident with that of another - means that savings can be effected through cooperation. Time diversity arrangements can take the form of "equichange", in which capacity and energy delivered by one system are returned at a later date or time by the receiving system. Alternatively, the services may be paid for in cash as they are supplied.

Optimization occurs on a cooperative basis when a group of utilities agree: (i) to assess all of the generating opportunities available to the group as a whole according to common objective criteria; and then (ii) to order these options according to the criteria stated. When different utilities have access to different resources, different technological specializations, and different siting opportunities, the evaluation procedure is likely to establish a hierarchy indicating the sequence with which the facilities in question should be developed. The effectiveness of this kind of cooperation is a direct function of the

extent to which decisions are based on the objective evaluation criteria. The more that parochial considerations play a part, the more likely it is that decisions will yield results that are sub-optimal relative to the other criteria.

Transmission Planning

The joint planning of interconnections is fundamental to all other kinds of inter-utility cooperation, and the benefits of interconnections are widely recognized. Less widely recognized, however, is the fact that groups of interconnected utilities may be able to achieve mutual benefits by integrating their transmission planning more generally. This is because any new transmission system will have implications for every utility within the interconnected network. For example, a given Canadian utility might benefit if one of its Canadian neighbours were to expand its north-south transfer capacity, because such an addition might result in the elimination of an operating constraint (imposed for reliability reasons) on the former utility's own north-south interconnections.

Export Marketing and Import Coordination

Cooperation for planning purposes normally begins within a given region, and many members in a regional partnership may, at the same time, be buying or selling electricity with utilities outside of the region. At some stage in the evolution of the partnership, it may be beneficial to coordinate these external transfer functions. When a given regional partnership is a net buyer from external sellers, savings can be achieved because cooperation enables the several members to make larger purchases and to negotiate as a single unit. When a given regional partnership is a net seller to external markets, cooperation enables the members to raise both the quantity and also the quality of any electricity being sold, thus raising the profitability of the selling transactions.

4.5 Arrangements Involving Wheeling

The third dimension of inter-utility cooperation concerns the *number* of the cooperating entities. The basic distinction is between arrangements that are bilateral and arrangements that are multilateral. The importance of this distinction is that multilateral cooperation involves *wheeling* in one form or another. Wheeling is the transmission of electricity from one utility, through the transmission network of another utility, for

delivery to a third party. Wheeling arrangements permit capacity and energy to be traded over wide geographic areas. Their essential feature is that intermediate utilities make excess transmission capacity available to other parties, subject to certain conditions, thus enabling sellers to have access to more than one buyer, and buyers to more than one seller.

A number of the functional arrangements described in section 4.4, relating to both operations and planning, could involve wheeling. However, wheeling raises a number of issues unique to itself, and it is therefore useful to discuss it separately.

There are different *kinds* of wheeling, and there are different *institutional modes* whereby wheeling can be effected. Fundamentally, wheeling can be divided into non-firm wheeling and firm wheeling. The institutional modes whereby wheeling can be effected fall within three separate classes: back-to-back purchase and sales agreements; energy marketing; and contract wheeling. These various concepts are described briefly below.

4.5.1 Basic Kinds of Wheeling

Non-Firm Wheeling

Non-firm (interruptible) wheeling agreements tend to be short-term and are unlikely to require the expansion of facilities. They arise mostly in operational contexts, when a utility wishes to replace its own high-cost generation with lower-cost generation purchased from another utility to which it is not interconnected. Such transactions can be interrupted according to conditions specified by the buyer, the seller or the wheeling entity.

Firm Wheeling

Firm wheeling can arise in either an operational or a planning context, when a buyer or seller is interested in contracting for firm power with another utility with whom it is not interconnected. The wheeling utility in this case is asked to provide a firm transmission path for the duration of a buy-sell contract. The utility requesting the wheeling service specifies the parameters of the service required, including such details as duration, schedule, locations of delivery and receipt, firmness desired, and the level of risk the two initiating parties are prepared to assume. The wheeling utility then typically conducts the

necessary power system studies to identify the impact of the requested service upon its system, taking account of its primary obligation to satisfy its own firm commitments at the lowest possible cost. These studies determine whether modifications are needed to the wheeling utility's transmission system to provide the requested service.

4.5.2 Institutional Modes to Effect Wheeling

Back-To-Back Purchase And Sales Agreements

Back-to-back purchase and sales agreements involve separate, but related, buy-sell contracts. The primary active agents are the ultimate buyer and the ultimate seller; they are the ones that initiate the necessary set of contractual arrangements. The intermediary plays a secondary role; it buys and resells the service for which the primary agents wish to transact, without changing the quality of the service in any fundamental way. The intermediary's profit comes from the difference between the purchase price and the sale price.

Energy Marketing

Although energy marketing and back-to-back purchase and sales may be difficult to differentiate in the context of this study, energy marketing may be defined as a situation wherein an intermediate utility initiates the bulk of the transactions, buying and selling capacity and energy in such a way that there is no necessary connection between the services bought and the services sold. What happens is that the intermediate utility buys a variety of electricity services, unbundles them, and then rebundles them in the form sought by customers. The rebundling is possible because the intermediary buys a variety of capacity and energy services and then combines these with the capacity and energy available on its own system. It may therefore be debatable whether a utility engaged in such simultaneous buying and selling is, in actual fact, engaged in wheeling. However, wheeling can be said to take place at least to the extent that the intermediary is both a buyer and a seller, even though it may be impossible to identify the specific wheeling service.

Contract Wheeling

The distinctive feature of back-to-back and energy marketing arrangements is that non-interconnected parties do not deal directly with one another. Contract wheeling occurs when the intermediate party agrees to provide a wheeling service *as such*, thereby enabling non-interconnected buyers and sellers to negotiate directly. The price of the wheeling service could be posted in advance or it could be negotiated on a case-by-case basis.

4.6 Cooperative Mechanisms

The fourth dimension of inter-utility cooperation concerns the formal and informal *mechanisms* that utilities put in place to enhance cooperation. Perhaps the best way to describe what is meant here is to begin by considering two limiting cases. At one extreme, utilities simply engage in *ad hoc* deal making with their interconnected neighbours, without a formal cooperative mechanism. At the other extreme, they merge with one or more other utilities into a single corporate entity, and the cooperative mechanism becomes a unified management structure reporting to a single board of directors. Between these two limits are various kinds of pooling arrangements, in which some functions are fully integrated and others are not; the more that functions are integrated, the "tighter" the pool.

To further specify this particular dimension, five points along the continuum are described below. While none of these may describe existing cooperative mechanisms perfectly, they serve to identify the range of possibilities.

Informal Deal Making

Informal deal making is the most common way in which utilities interact with one another. Each transaction is approached separately, and decisions are taken on a case-by-case basis. The amount of cooperation will vary as circumstances warrant, and at any given time it may be extensive or virtually non-existent. When arrangements are wholly informal, each utility regards itself as a fully independent entity responsible for meeting its own load as economically and as reliably as possible; autonomy with respect to both operations and planning is thus retained to a very high degree.

Loose Pooling

Loose pooling may be defined as a situation wherein a group of utilities agrees to coordinate their operational functions in some way. The exact mechanism employed could be very informal (e.g. system operators could simply develop, over time, a set of mutually acceptable operating procedures) or very formal (e.g. the pooling entities could establish a central office responsible for implementing a negotiated - and therefore well-defined - set of activities).

One of the most effective ways for a group of utilities to establish a loose pool would be for them to centralize their unit commitment and economic dispatch functions, so that decisions as to which generating units will be committed and economically dispatched to serve the combined system load are made from one common operating point. With centralization of the commitment and dispatch functions, wheeling is completely unobstructed and the central operator has all the information necessary to supply energy and capacity requirements at the lowest possible cost consistent with system-wide reliability criteria.

In addition to the above kinds of arrangements, a loose pool could also centralize operational planning functions, including reserve assessments, maintenance scheduling, short-term load forecasting, and the specification of transmission constraints and equipment settings.

Energy Brokering

The coordination of unit commitment and economic dispatch can be achieved in other ways. In an energy brokering system, for example, a group of utilities establishes a centralized information centre to compile buy/sell and wheeling quotes from each participating member. This information is then made available to all, permitting mutually beneficial economic arrangements to be struck whenever it is advantageous to do so. In theory, such a system is as efficient as centralized commitment and dispatch, because, once again, all of the relevant information is available to participants in the pool, and each participating member has an interest in taking advantage of the most economic opportunities available.

Tight Pooling

A tight pool is a formal arrangement among two or more utilities involving the coordination of operational functions and also the integration of planning functions. The integrated planning that tight pooling entails could evolve out of the operation of a loose pool. The advantages of tight pooling are that a certain amount of duplication can be avoided and a higher degree of optimization can generally be achieved.

Corporate Merger

In the mechanisms described above, each participating utility retains its individuality and decision-making autonomy. The next logical step after tight pooling is one where the cooperating entities decide to capture all of the possible benefits of cooperation by becoming a single corporate entity. Theoretically, such mergers make sense provided that the economies of scale achieved by full integration are not outweighed by diseconomies.

Another type of cooperative mechanism is joint project development, and this is described below:

Joint Project Development

Situations may arise when two or more utilities cooperate for purposes of developing a large new generation and transmission facility. Such agreements can also involve other considerations, such as the management of reservoirs on a common river system. While joint project agreements can be very complex and can entail a very high degree of inter-linkage between the cooperating systems, the planning functions tend to be confined to the specific project, and the operations are thereafter governed by the terms of the contract. Further integration of the utilities' planning functions is generally not included. Project sharing agreements can be for a fixed period of time or for the whole life of the project in question. The capacity and energy output is only as firm as the facility itself.

4.7 The Time Dimension

Any given arrangement between utilities will be for a particular period of time, ranging from minutes for certain operational functions to decades for long-term purchase and

sales contracts. Generally speaking, operational arrangements will have a shorter duration than planning arrangements, although designations such as "short term" and "long term" could apply to each. Short-term arrangements, although they receive considerably less attention than large long-term agreements, are no less significant; indeed, because they are reasonably easy to negotiate and permit considerable functional scope, shorter-term arrangements must be regarded as an important focus for the continued evolution of inter-utility cooperation.

4.8 The Economic Dimension

Most inter-utility cooperation agreements define financial terms and conditions describing how the benefits of the arrangement are to be shared. Where the financial parameters themselves are not precisely specified, the agreement is likely to define a process whereby they are to be determined. For example, certain interconnection agreements specify that the rates of payment for certain kinds of transactions are to be negotiated by the relevant operating committee.

This study does not focus on financial parameters as such but seeks to determine the extent to which inter-utility cooperation has led to economic benefits in the past, and the extent to which it could lead to additional benefits in the future. These benefits are identified in general (qualitative) terms in this chapter and, as far as possible, in quantitative terms in the following chapter.

4.9 The Environmental Dimension

Environmental issues are becoming increasingly relevant to decisions that must be made concerning the sources of new electricity generation and the siting of new generation and transmission systems, and inter-utility cooperation may be able to provide significant benefits in this regard. For example, cooperation could reduce total capacity requirements. Second, it could result in patterns of electrical energy production that are environmentally preferable to those that would be obtained in the absence of cooperation. Third, inter-utility cooperation could permit sources of generation that are environmentally benign to proceed before sources that are less benign. Finally, cooperation could result in transmission lines being built in areas that are less environmentally sensitive than would otherwise be the case.

4.10 The Geographic Dimension

Cooperative arrangements among electrical utilities can be intraprovincial (involving utilities within a single province), interprovincial (involving utilities in more than one province), or international (involving utilities in both Canada and the United States). International arrangements can, in turn, be divided into two types: simple (where there is only one Canadian utility involved); and composite (where there are two or more Canadian utilities involved). Among North American utilities, the geographic extent of inter-utility cooperation tends to depend on the particular function or objective. With respect to reliability, for example, cooperation is extended throughout the continent as a whole. In other respects (e.g. systems planning), cooperation is much more narrowly confined. In Canada, the primary geographic units for purposes of electricity cooperation tend to be defined by provincial boundaries. In the United States, there are no natural units in this sense, and highly coordinated and integrated entities often extend across several states.

As was noted at the outset, the primary focus of the present study is *interprovincial* electricity cooperation. However, it is not possible to describe the full extent to which interprovincial cooperation can evolve without taking account of both international and intraprovincial cooperation.

4.11 Conclusions

The framework for inter-utility cooperation described in this chapter is not the only one that could be developed. Nor are the various functional arrangements and cooperative mechanisms described above comprehensive; other possibilities no doubt could, and perhaps should, be included. Nevertheless, the framework outlined here should be sufficient to describe most of the more significant types of cooperation that are prevalent now and that are potentially realizable in the future.

4.12 Benefits And Constraints

4.12.1 Benefits

The objectives of inter-utility cooperation are to achieve net economic benefits, risk reduction, improved reliability, and environmental benefits through interconnecting

contiguous electric utility systems and coordinating, to some degree, their planning and operating functions.

The realization of these benefits would be reflected in reduced costs and rates which would tend to favour increased economic activity. It also promotes the development of the best future resources from both economic and environmental viewpoints.

Inter-utility cooperation in operations and planning can be divided into two main categories: transactions and coordination. Economic, environmental and reliability benefits can result from both categories as described below.

Benefits from Transactions

In operations, benefits could result from economy energy transactions, non-economy capacity and energy transactions, and wheeling arrangements. Similarly, in planning, benefits could be gained from purchase/sales agreements and wheeling agreements.

Benefits from Coordination

In operations, benefits can be increased by coordinating the following functions among the participating utilities:

- establishment of common operating criteria;
- sharing operating reserves;
- economic dispatch and river control;
- maintenance scheduling;
- load frequency control; and
- emergency support.

In planning, further benefits could result from coordinating the following functions among the participating utilities:

- establishment of common planning criteria;
- reserve sharing;
- generation planning;
- transmission planning;

- export marketing and import coordination; and
- emergency support.

4.12.2 Constraints

The benefits of integrated (or pooled) operation of a number of power systems can only be achieved if a number of constraints can be accepted or overcome.

These constraints include possible increased transmission costs, organizational and institutional difficulties, regional disparities, and risk of cascading failures.

Possible Increased Transmission Costs

Typically, additional transmission capacity (both intra-system and inter-system) is needed to more fully integrate electric power systems. This may entail additional capital, operating and environmental costs. Also it is becoming increasingly difficult and time consuming, as well as more costly, to obtain transmission rights-of-way.

Organizational And Institutional Difficulties

Organizational difficulties are a function of the number of local managements involved. Institutional difficulties are those related to conflicts among the interests of individual power pool members and those of the pool as a whole.

Since the interests of a power pool can never be entirely coincident with those of its constituent members, a certain degree of individual management autonomy must, of necessity, be sacrificed in order to realize in full the benefits of the pooling arrangements.

Potential conflicts with individual interests may be avoided, or at least minimized, by formulation at the outset of clear and firm agreements on fundamental guiding principles, which will later provide a basis for any necessary compromises on details.

It is also most essential that the pooling agreement should contain adequate assurance as to the expected continuity of the pool.

The following are illustrative of the type of conflicts of interest and difficulties which commonly arise.

In cases where the pool is composed of members with different financial structures and costs of raising capital there may be differences of views as to the profitability of projects in terms of eventual recovery of the original investments. Such conflicts are likely to be minimal where provincially-owned utilities are concerned. Nevertheless, it may be the case that a particular plan, which maximizes benefits from the pool viewpoint, does not do so from the viewpoint of an individual member. In such cases, compensatory adjustments may be made in the distribution of benefits.

Another area in which conflict may arise is in the allocation of generation reserves among the pool participants. This allocation may be made proportional to each member's annual peak load, but in cases where large disparities exist among annual peak loads, the argument may be advanced that such an allocation gives too large a share of the savings in reserves to the smaller utilities. Conversely, where the participating utilities are comparable in size this type of disagreement is less likely to arise. In any case, it is essential that agreement be reached on a suitable formula for the equitable sharing of these benefits.

Difficulties may also arise in the allocation of costs of interconnecting and internal transmission facilities made necessary by the pooling arrangements. Some of the formulae required for this purpose may be relatively complex and their development demands a high degree of cooperation among participants.

In power pools it has frequently been the case that individual utilities will insist that they not be compelled to install facilities as recommended in the overall plan, thus retaining the power of veto with regard to their own expenditures, although subject to a penalty if the departure from the recommended plan results in an increase in reserve requirements for the pool. The financial resources of a given utility may be insufficient to proceed with a recommended unit, but this type of difficulty can usually be resolved by resorting to bilateral or multi-lateral financing arrangements with the other pool members.

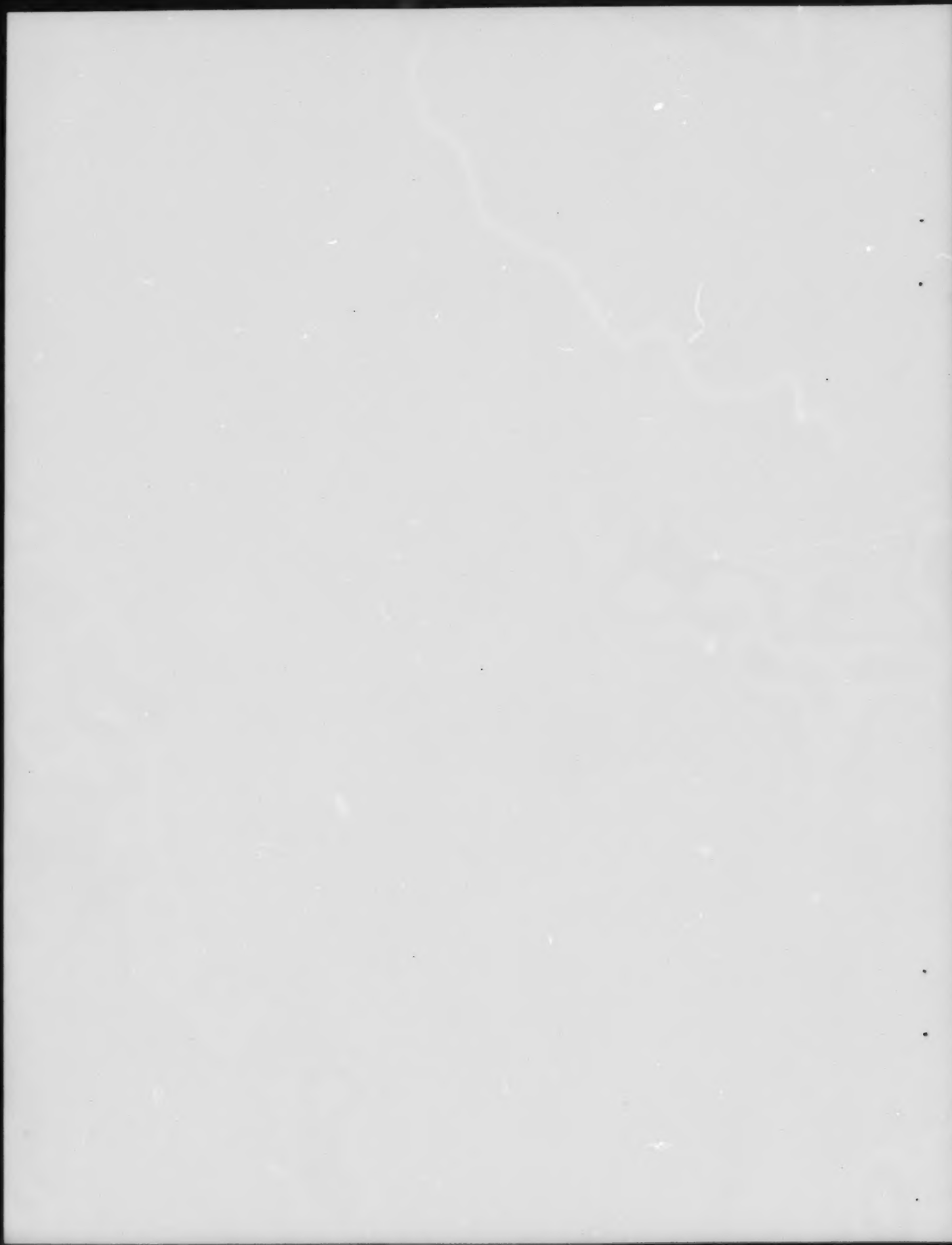
Regional Developments

Many provinces perceive that there are considerable income and employment benefits associated with the *installation* of electricity generating facilities. Thus, they prefer to build these facilities in-province rather than enter into arrangements that would result in them being built out-of-province. Income and employment benefits tend to be immediate and highly visible. The benefits of cooperation tend to be long-term and invisible.

Risk Of Cascading Failures

As the size of a fully coordinated system grows, the frequency of major shutdowns resulting from unusual system disturbances decreases. As the pool size increases, the number of initiating causes required to produce a cascading outage and a major shutdown also increases. The more numerous the initiating causes, the less probable they are to occur.

5. THE EXTENT OF INTER-UTILITY COOPERATION IN CANADA



5. THE EXTENT OF INTER-UTILITY COOPERATION IN CANADA

5.1 Introduction

This chapter summarizes the information received in response to the Board questionnaire sent to utilities and other interested parties in March, 1990. Using this information, the chapter describes the extent of existing and proposed inter-utility cooperation in Canada, as well as the benefits derived from such cooperation. It outlines the utilities' opinions concerning the role of independent power producers, and their views on actions required from utilities, provincial governments and the federal government which would assist in bringing about new cooperation initiatives.

5.2 Interconnections

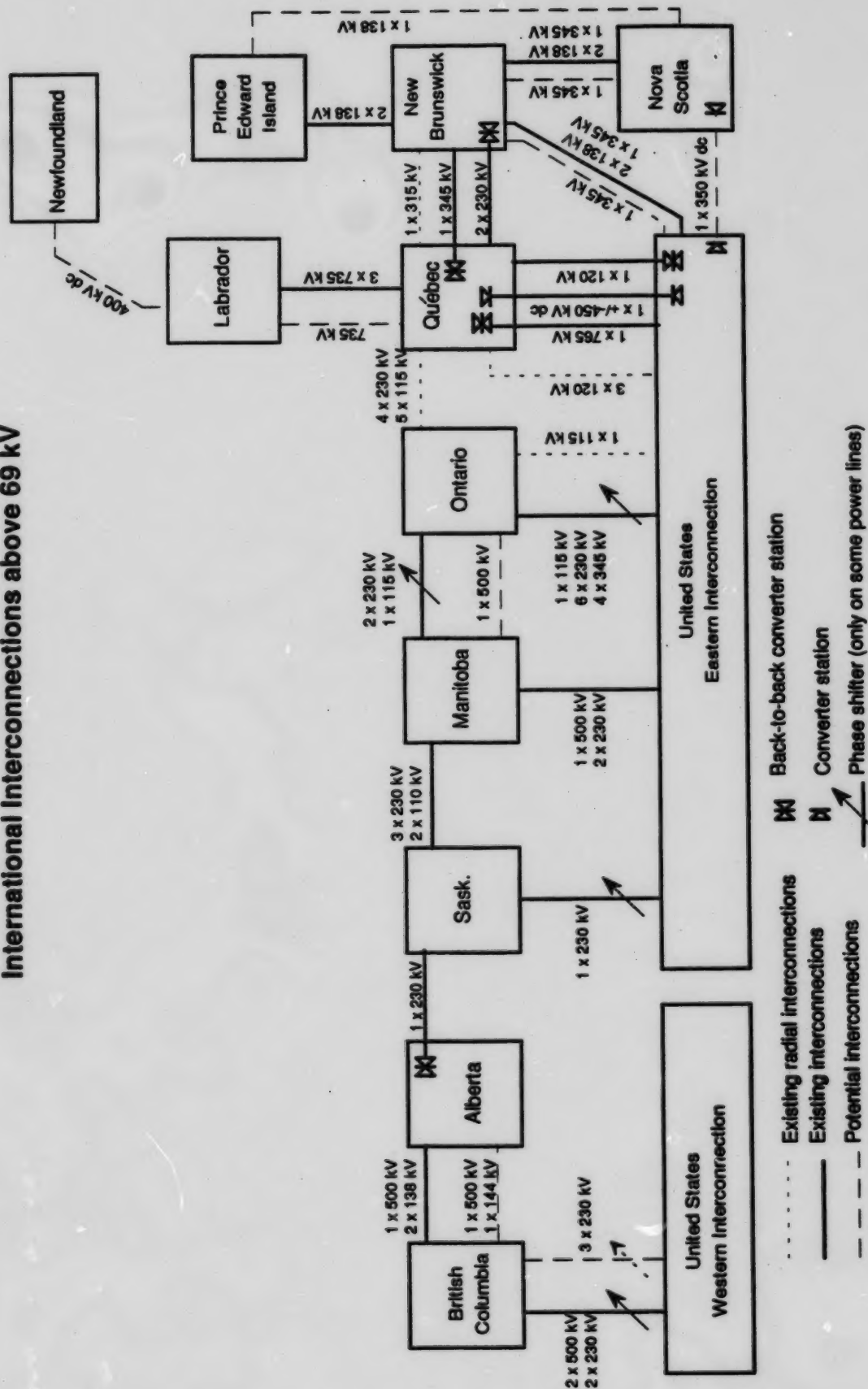
Interconnections are the transmission lines which connect individual utility systems and allow inter-utility transactions to take place. In North America, most such interconnections are of the alternating current (AC) type which tie together two entire utility systems and operate in parallel with other transmission paths. There are also a small number of radial AC interconnections which tie only a small portion of one system to a portion, or the whole, of another system.

Some AC interconnections incorporate phase shifters which provide some control of the power flows in parallel transmission paths. Direct current (DC) interconnections provide full control of power flows and are also used where large blocks of power must be transmitted over long distances or where, for technical reasons, AC transmission would not be suitable.

Existing and proposed interprovincial and international interconnections, together with their transfer capacities, are illustrated in Figures 5.1 and 5.2, and listed in Tables 5.1 and 5.2.

The provincial electric systems (with the exceptions of Québec, and Newfoundland and Labrador) are synchronously interconnected through AC ties to either the U.S. Eastern or the U.S. Western Interconnected Systems. The British Columbia and Alberta systems are

Figure 5.1
Existing and Potential Interprovincial and
International Interconnections above 69 kV



Transfer Capabilities of Existing and Potential Interprovincial and International Interconnections above 69 kV and Provincial Installed Generating Capabilities (MW)

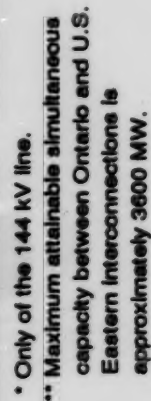


TABLE - 5.1 Capacity of Existing and Potential Interprovincial Interconnections

Connection	Type	Voltage (kV)	CAPACITY (MW)		
			design	from (1) to (2)	from (2) to (1)
British Columbia (1) - Alberta (2)	existing	1x500 + 2x138	1400	1200	1000
	potential	1x500	NA	NA	NA
	potential	1x144	150	150	40
Alberta (1) - Saskatchewan (2)	existing	1x230	150	125	125
Saskatchewan (1) - Manitoba (2)	existing	3x230	925	200	150 - 300
	existing	2x110	152	152	NA
Manitoba (1) - Ontario (2)	existing	2x230 + 1x115	454	354	354
	potential	1x500	3000	1146	NA
Ontario (1) - Québec (2)	existing	4x230	1300	96	1300
	existing	5x115	260	105	205
Québec (1) - Labrador (2)	existing	3x735	6600	NA	5300
	potential	1x735	2200	NA	2200
Québec (1) - New Brunswick (2)	existing	1x315	250	170	NA
	existing	1x345	450	380	380
	existing	2x230	600	550	350
New Brunswick (1) - Prince Edward Island (2)	existing	2x138	200	140 (1)	40
New Brunswick (1) - Nova Scotia (2)	existing	1x345 + 2x138	1000	400	400
	potential	1x345	872	300	300
Prince Edward Island (1) - Nova Scotia (2)	potential	1x138	100	100	100

NOTES: - the total design capacities of these interconnections may differ from the sum of the design capacities or flow limits of the individual interconnections.
 - all Québec's interconnections are DC type or radial type AC
 - Alberta-Saskatchewan interconnection is DC type
 (1) limited to available load in P.E.I.

TABLE - 5.2 Capacity of Existing and Potential International Interconnections

Connection	Type	Voltage (kV)	CAPACITY (MW)		
			design	from (1) to (2)	from (2) to (1)
British Columbia (1) - BPA (2)	existing	2x500	4120		
		2x230	746	2300	2300
	potential	3x230	3200	1900	1900
Saskatchewan (1) - North Dakota (2)	existing	1x230	150-200	150-200	150-200
Manitoba (1) - Minnesota (2)	existing	1x500 + 1x230	1500		
Manitoba (1) - North Dakota (2)		1x230	500	1450-1900	830
Ontario (1) - Minnesota (2)	existing	1x115	150	150	150
Ontario (1) - New York (2)	existing	3x345 + 4x230	4150	2200	2200
	existing	1x115 + 2x69	370	370	370
Ontario (1) - Michigan(2)	existing	2x345 + 2x230	2840	2000	2000
Québec (1) - New York (2)	existing	1x765 + 2x120	5325	2675	2495
Québec (1) - New England (2)	existing	1x450(dc) + 2x138	2480	1010	990
New Brunswick (1) - New England (2)	existing	1x345 + 2x138			
		3x69	946	900	30
	potential	1x345	300	300	NA
Nova Scotia (1) - New England (2)	potential	350 dc	1200	1200	1200

NOTES: - the total design capacities of these interconnections may differ from the sum of the design capacities or flow limits of the individual interconnections.
 - all Québec's interconnections are DC type or radial type AC

connected to the Western Interconnected Systems and the other provincial systems to the Eastern Interconnection. Since an AC interconnection between Alberta and Saskatchewan would have been inadequate to maintain synchronism between the Eastern and Western systems, a DC link was used when these two provinces were interconnected in 1989. For similar reasons, interconnections between Québec/Labrador and the other Canadian and United States systems are either DC or radial AC ties. The electric system on the Island of Newfoundland is isolated from the other systems in Canada and United States.

There are 33 existing major interprovincial interconnections, ranging in voltage from 110 kV to 735 kV, with a total transfer capability of some 10 000 MW. There are a further 7 proposed interprovincial interconnections, ranging in voltage from 138 kV to 735 kV, with a total transfer capability of about 5000 MW.

Existing major interconnections with the United States number 34, ranging in voltage from 69 kV to 765 kV, with a total transfer capability of some 13 000 MW. There are a further 5 proposed international interconnections, ranging in voltage from 230 kV to 350 kV, with a total transfer capability of about 3400 MW. Including minor transmission interties, there are over 100 existing international transmission lines.

Comparing existing interprovincial and international interconnections, it can be seen that the total transfer capability of the international ties (about 13 000 MW) is considerably greater than that of the interprovincial ties, (about 10 000 MW), particularly when the interprovincial ties include the Labrador-Québec 5 300 MW interconnection. This difference results from relative market potential, relative proximity to loads, and greater economic attractiveness of the international export markets.

It is evident that there is already considerable existing and potential interconnection capacity, both interprovincial and intraprovincial, which permits the achievement of a significant degree of mutually beneficial inter-utility cooperation.

5.3 Existing Cooperation Agreements

Virtually all of the utilities responding to the Board questionnaire have interconnection agreements with neighbouring utilities in Canada and the United States. Typically, the basic purposes of such agreements is to provide mutual assistance during emergencies, to

improve the reliability of bulk power supply by coordinating operations, to realize operating economies by exchange of surplus power and energy, and to the extent mutually desirable, to secure additional economies through coordinated development. Items covered include reserve sharing in emergencies, coordination of operating and planning reserves, and coordination of equipment maintenance schedules.

Significant economic benefits are realized from these agreements. For example, New Brunswick Power estimated that the benefits it derived from such agreements with three utilities in Maine, Hydro-Québec, Nova Scotia Power, and Maritime Electric for 1989/90 amounted to some \$41 million. Under the Alberta Interconnected System Power Pool agreement, 1989 benefits to TransAlta Utilities were approximately \$28 million and to the Alberta Interconnected System as a whole about \$48 million.

The majority of the utilities have purchase and sales agreements with adjacent Canadian and United States utilities. These agreements generally involve the purchase and sale of firm capacity and/or energy or surplus energy. They may also involve seasonal diversity, peaking, or unit participation agreements, and arrangements for the transmission of capacity and energy.

Manitoba Hydro has various agreements with utilities in both the U.S. and Canada. An existing diversity exchange (300MW) and summer sales (200MW) agreement with a U.S. utility expires in 1993, but has had estimated benefits of \$27 million (1980 \$). A further 200 MW summer peaking sale has been negotiated from 1993 to 1996, with total benefits estimated at \$8.6 million (1986 \$). Manitoba Hydro also has an agreement to sell 500 MW of firm capacity to the U.S. with benefits totalling \$402 million (1984 \$). It also has various agreements with Ontario Hydro, including a 1 000 MW long-term sale with benefits estimated at \$847 million (1988 \$).

Maritime Electric estimates that savings from its power purchase agreement with New Brunswick Power for 20 MW of firm power are about \$7 million from 1985 to 1989, inclusive.

At present, most utilities are involved in very little wheeling and what little is done is largely to supply their own isolated loads through an intervening system, or to deliver contracted power under a unit participation or similar agreement.

Almost all of the utilities are members of one of the regions making up the North American Reliability Council (NERC) and, as such, abide by the Council's operating and planning criteria.

Operating reserve coordination and emergency support are carried out by all utilities.

Reserve sharing for planning purposes is common to most utilities.

There is very little inter-utility economic dispatch practised, except for the limited version carried out by the Maritime utilities. However, the Alberta utilities practise intraprovincial economic dispatch.

Coordinated maintenance scheduling and load frequency control are performed by somewhat more than half of the utilities.

There is very little integrated generation and transmission planning. An exception is in the case of the Alberta utilities which carry out intraprovincial planning. The Maritime utilities engage in a certain degree of planning coordination. Also Winnipeg Hydro and Manitoba Hydro do intraprovincial planning.

There are no existing instances of export marketing or import coordination.

The only examples of tight pooling in the operating and planning modes are among the Alberta utilities and between Winnipeg Hydro and Manitoba Hydro.

About half of the utilities participate in some form of loose pooling arrangement. An example is the Northwest Power Pool which includes B.C. Hydro, West Kootenay Power, TransAlta, Edmonton Power and a number of utilities in the U.S. Pacific Northwest.

There are no existing energy brokering arrangements.

There are some instances of forms of joint program development for generation and transmission. Examples are the Maritime and Alberta utilities.

Informal deal making is a cooperation mechanism preferred by most utilities.

In a qualitative sense, the benefits conferred by inter-utility cooperation include enhanced economic benefits, improved reliability and environmental improvements.

Economic benefits may include those due to reduced reserve margins, installation of the most economic generating units, economies of scale, economy energy interchanges, seasonal and/or time diversity, synergy and energy retiming.

Reliability benefits may include reduced demand-side risks, emergency support and reduced fuel dependency risks.

Environmental benefits can result from increased system efficiencies leading to reduced fuel use, as well as use of more environmentally benign types of generation.

5.4 Future Cooperation Initiatives

The following paragraphs list possible new cooperation initiatives foreseen by the utilities for the period 1990-2010, together with their perceptions of the conditions necessary to bring about these initiatives.

B.C. Hydro/POWEREX

- a) A Coordination Agreement with TransAlta Utilities on behalf of the Alberta generating utilities (Alberta Power, Edmonton Power and TransAlta Utilities) which would include: (i) firm energy and capacity transactions, economy energy and storage, purchase and sales agreements, and planning and reserve sharing; (ii) non-firm and firm wheeling, energy marketing and contract wheeling; and (iii) loose pooling. B.C. Hydro has the required excess capacity and the Alberta generating utilities have the required excess energy so that this initiative could proceed subject to favorable conditions relative to economics and internal and external demand.
- b) A Coordination Agreement with Bonneville Power Administration which would entail expansion of an existing non-treaty storage agreement. This is expected to be viable under existing and expected conditions and to be relatively immune from changes in these conditions.

- c) An Interconnection Agreement with Washington Water Power which would include: (i) economy energy and storage, and firm capacity and energy transactions; (ii) non-firm and firm wheeling, energy marketing and contract wheeling; and (iii) informal deal making. Necessary conditions include stable economic conditions, stronger northwest and southwest U.S. markets, and internal demand comparable to forecast.
- d) An Interconnection Agreement with Puget Sound Light and Power with functional characteristics as in c). This is expected to be viable under existing and expected conditions, but could be jeopardized by energy surpluses in the U.S. Pacific Northwest.
- e) A B.C. Hydro/POWEREX Wheeling Policy which would include: (i) long-term firm (LTF) transmission access with pricing based on long-term marginal cost plus system support and administration; (ii) LTF wheeling according to an agreed schedule and direction with time differentiated pricing based as above; and (iii) provisional LTF wheeling on short-term firm spare transmission capacity with pricing based on opportunity cost for the provisional period plus system support and administration. This initiative would require stable economic conditions and firm external markets.
- f) The POWEREX Pool Operation (PPO) would be operated by POWEREX, a marketing operation serving short-term bulk electricity markets in and outside B.C., including Alberta and the western United States. PPO would facilitate short-term transactions and realize competitive opportunities and efficiency gains to benefit B.C., and would use the B.C. Hydro system to store and transmit electricity. Hourly, monthly and yearly term prices would be posted based on market conditions. PPO would buy and sell short-term energy, store energy for producers and consumers, engage in short-term firm and interruptible wheeling, lend energy to producers, and buy and sell short-term capacity. PPO is expected to be viable under existing and expected conditions. Adoption of market-driven marketing by others would enhance this initiative.

Cominco

Cominco may arrange to have B.C. Hydro wheel power from Trail to its Highland Valley Copper operation and to have B.C. Hydro wheel to Cominco's Alberta operations. These initiatives would involve firm energy and capacity. Wheeling, shaping and storage services would have to be available at reasonable cost.

West Kootenay Power

No future initiatives are currently planned.

TransAlta Utilities

- a) A Coordination Agreement with B.C. Hydro/POWEREX, on behalf of Alberta Power, Edmonton Power and TransAlta, with the basic purpose of realizing benefits from increased coordination of the two systems, largely through hydro/thermal synergy, and would include: (i) B.C. Hydro's purchase of firm surplus energy to defer new generation in B.C.; (ii) TransAlta's purchase of firm surplus capacity from B.C. Hydro, to defer new generation in Alberta; (iii) export to the U.S. of surplus capacity from B.C. together with surplus energy from Alberta; and (iv) coordinated operation resulting in non-firm exports and fuel displacement. Necessary conditions would include the need for each system to acquire the surplus energy (from Alberta) and capacity (from B.C.) of the other system.
- b) Western Electric Utility Cooperation. Participants would be B.C. Hydro, TransAlta, Alberta Power, Edmonton Power, SaskPower, Manitoba Hydro, and the provinces of B.C., Alberta, Saskatchewan, and Manitoba. Benefits are expected to come from hydro/thermal synergy, reserve sharing, time diversity, economy energy interchanges, and joint project development providing for further generation optimization. A two-phase study of the coordination potential between B.C. Hydro and Alberta was completed, and identified significant potential benefits due primarily to the hydro/thermal synergy which exists between the two provinces. A similar study was undertaken by SaskPower and Manitoba Hydro which identified coordination benefits that were much less than those of the B.C.-Alberta study. Primarily this result is attributable to the already

balanced hydro/thermal mix in Saskatchewan and Manitoba Hydro's coordinated planning and operations with Ontario Hydro and U.S. utilities. For similar reasons, the potential benefits between Saskatchewan and Alberta appear minimal. Plans for a formal four province study have been put on hold indefinitely since it does not appear that such a study would indicate significant benefits in addition to those already identified.

- c) Export of capacity and energy to the United States. Participants would be U.S. utilities, Alberta Power, Edmonton Power, and TransAlta, with the basic purpose of accessing the growing markets in the Pacific Northwest and California. This would involve export agreements for short and long-term sales of: (i) firm and/or interruptible capacity and energy; and (ii) deferral of operation and construction of U.S. generation. This capacity and energy would come from surplus or dedicated Alberta generation. Consumers in Alberta would benefit when prebuilt dedicated generation was repatriated to supply Alberta load. Alberta could also purchase spill energy from the U.S. to displace more expensive thermal generation. Necessary conditions would include increased U.S. demand, successful negotiation of wheeling access through the B.C. Hydro system to the U.S., and the agreement of the two provincial governments.

Alberta Power

Alberta Power mentions only one initiative, namely Western Electric Utility Cooperation. It is also involved in initiatives as an Alberta generating utility similar to those described by TransAlta.

Edmonton Power

No new cooperative agreement is being contemplated in the near future, except Western Electric Utility Cooperation, and in those initiatives as an Alberta generating utility similar to those described by TransAlta.

SaskPower

Two initiatives were mentioned: Western Electric Utility Cooperation; and a joint study with Manitoba to assess the benefits of increased coordination, joint dispatch and a fully integrated resource plan.

Manitoba Hydro

While stating that, at this time, specific future initiatives could not be identified, Manitoba Hydro mentioned the following general trends:

- a) To strengthen interconnections with other utilities. For example, the 500 kV transmission line to Ontario Hydro's eastern system will facilitate future transactions with Ontario, and transfer capability to the U.S. is planned to increase by 300 MW sometime between 1993 and 1995.
- b) Manitoba Hydro is a participant in the Western Electric Utility Cooperation task force study.
- c) Manitoba Hydro feels that action to reduce atmospheric emissions will increase the attractiveness of Manitoba's hydro power.

Ontario Hydro

- a) Purchases from Manitoba Hydro of 200 MW from 1998 to 2003 and of 1000 MW from 2000 to 2022, coordinated so that the maximum delivery does not exceed 1000 MW. New transmission required from the Manitoba border through northwestern Ontario to northeastern Ontario will be 500 kV AC. Timing and circumstances of this deal were favorable; the utilities' relationship is good, there was need for new transmission in Ontario, costs were close to those of alternatives, new supply was needed, and diversity of supply was desired. For Manitoba, Ontario was a good market, and there was need for energy banking/energy exchanges.
- b) Possible deals with Hydro-Québec may include:
 - Diversity exchanges based on thermal/hydro synergy.

- Buy/resell, emergency assistance and wheeling arrangements.
- New transmission requirements between southeastern Ontario and southwestern Québec to provide bilateral transfer capability.
- No arrangements likely prior to the turn of the century.
- Duration probably 5 to 10 years.

These arrangements could involve thermal/hydro synergy, wheeling, export marketing and import coordination, and informal deal making. Required conditions may include need for supply, energy banking/diversity exchanges, need to improve market access, sales benefits, need to improve Québec supply reliability, and possible benefits in transmission reliability.

c) Possible deals with Manitoba/Saskatchewan may consist of:

- Coal-by-wire, oil/gas by wire in emergencies.
- Diversity exchanges based on thermal/hydro synergy.
- Unknown transmission requirements.
- No arrangements likely prior to the turn of the century.
- Duration probably 3 to 10 years.

These arrangements could entail purchase agreements, economy energy, wheeling by Manitoba and Saskatchewan, informal deal making (with possible provincial-level cooperation on energy supplies or other exchanges), and additional transmission in Ontario. A study of global emissions may show benefits. Necessary conditions may include need for supply, desire to minimize global emissions, economy energy costs, improved markets/supply access, and supply diversity/reliability.

Hydro-Québec

- a) A contract for the sale of 500 MW of firm power to Vermont Joint Owners for a thirty-year period beginning in the mid - 1990's..
- b) A contract for the sale of 1 000 MW of firm power to New York Power Authority starting in the late 1990's.
- c) A contract for the sale of 800 MW to New York Power Authority to take advantage of summer/winter diversity for the period 1999 to 2018.
- d) In conjunction with the contracts outlined above in (a) and (b), an objective of achieving the export of a total of 3500 MW of firm power and energy beginning in the year 2000.
- e) Power purchase contracts with N.B. Power and New York Power Authority.
- f) Possible new interconnection with Ontario Hydro.

These would all be long-term firm power and energy contracts. Initiative c) would also be a seasonal diversity arrangement. No wheeling is involved. All initiatives would involve formal deal making. Projects a), b) and c) are already subjects of contracts between Hydro-Québec and the parties concerned. Hydro-Québec's development plan allows for the construction of the required facilities. Project d) depends on the successful outcome of ongoing negotiations. The resulting contracts may contain clauses which share the risk of changes in Québec's internal demand and available hydraulic energy.

{The announcement in March 1992 by the New York Power Authority of its termination of the contract to purchase 1000 MW of firm power from Hydro-Quebec for a 21-year period starting in the late 1990's may have an impact on the development plan outlined above.}

New Brunswick Power

- a) The sale to Hydro-Québec for a 20-year period of up to 400 MW of capacity and energy from gas turbines installed on N.B. Power's system, in order to meet

Hydro-Québec's peaking requirements and provide economic benefits to N.B. Power. This project was commissioned in 1991.

- b) The construction of a 138 kV transmission line in New Brunswick to allow the second New Brunswick-Prince Edward Island cable to be in continuous service, to improve service reliability for Maritime Electric, and to allow the sale of more economy energy to P.E.I.
- c) Marketing of a 600 MW package to various Canadian and U.S. utilities for a 10 to 20-year period to benefit N.B. Power.
- d) The construction of additional transfer capability to Maine in three stages from 700 to 2000 MW to sell more power to Maine, as well as allow for possible transfers from Québec and Nova Scotia to Maine. This could involve a joint arrangement with Maine for wheeling to New England or wheeling from Hydro-Québec and Nova Scotia Power to New England. It could also entail arrangements ranging from joint equity entitlement to a joint venture with U.S. utilities, with NB Power as a marketing agent.

Initiatives a) and b) depend upon the need by Maritime Electric and Hydro-Québec for power and energy, and the realization of economic and reliability benefits to buyer and seller. Initiative c) requires demand over a 10 to 20-year period at a profitable price, competitive pricing and transmission access through New England. Initiative d) requires utility and regulatory support in the U.S. and Canada, benefits to N.B. Power and the purchasers, and risk sharing on new generation and transmission facilities.

Nova Scotia Power

- a) Increase in interconnection capacity to N.B. Power by construction of a new 345 kV transmission line to be installed in 2010 under terms similar to the existing interconnection agreement. Possible benefits could include firm sales/purchases to/from N.B. Power, increased energy exchanges, reductions in systems peaking capacity and power system stability considerations.

- b) The Bluenose Project involving the possible sale of coal-fired power to New England utilities for up to 30 years. This would require the construction of dedicated generation and transmission facilities including two HVDC submarine cables from Nova Scotia to New England. Contracts would involve cost based rates with demand and energy pricing, competitive coal prices, energy dispatch controlled by purchasers, opportunity for ownership participation in the generation and transmission facilities, and opportunity to trade in at-will energy transactions. To move the project forward would require a commitment from the utilities involved.

Maritime Electric Company

- a) Point Lepreau Unit Participation Agreement with N.B. Power to provide a 20 MW entitlement of capacity and energy from Point Lepreau No. 1 for a 3-year period starting in 1991. Lack of natural resources for electricity generation and the small size of the Island load make it desirable to participate in base load generating units in neighbouring provinces.
- b) Belledune Unit No. 2 Ownership Participation Agreement with N.B. Power to provide an ownership share from 1994, for the service life of the unit. Reasons are the same as those given for a), above.
- c) Belledune Unit No. 2 Transmission Agreement with N.B. Power to provide wheeling of Maritime Electric's share of the unit from 1994, for the service life of the unit.
- d) Point Aconi Unit No. 1 Ownership Participation Agreement with NSPC to provide an ownership share from 1994, for the service life of the unit.
- e) Point Aconi Unit No. 1 Transmission Agreement with NSPC to provide wheeling of MECL's share of the unit from 1994, for the service life of the unit.
- f) Point Aconi Unit No. 1 Wheeling Agreement with NB Power to provide wheeling of MECL's share of the unit from 1994, for the service life of the unit.
- g) An Interconnection Agreement with Nova Scotia Power from the year 2000 for an indefinite time, to provide a basic framework for inter-utility purchases. This

would involve economy energy, non-economy capacity and energy, informal deal making, and emergency support. Interconnection with Nova Scotia would probably only be made if it were impossible to achieve satisfactory access to Nova Scotia Power through negotiation with N.B. Power and utilization of existing interconnections.

Newfoundland and Labrador Hydro

- a) A new interconnection with Hydro-Québec via a new 735 kV transmission line from Churchill Falls to the Québec system as early as 1999, to increase transmission capability by 2200 to 2500 MW. This initiative is tied to the development of the Gull Island and Muskrat Falls hydro-electric projects, in Labrador. Development of these sites depends upon the ability to obtain firm contracts to market their output at satisfactory prices. Newfoundland and Labrador Hydro desires to purchase up to 800 MW of the output of these projects, but the balance must be sold elsewhere to make the projects feasible.
- b) A Labrador - Newfoundland Island Interconnection involving the construction of a ± 400 kV interconnection from Gull Island to St-John's as early as 1999, to transmit new Labrador power to the Island of Newfoundland. This interconnection could be financed through the Lower Churchill Development Corporation which is owned 51% by Newfoundland and 49% by Canada.

5.5 The Role of Independent Power Producers

Concerning the possible role of independent power producers (IPPs) in facilitating interprovincial cooperation, the following summarizes the responses obtained.

Cominco

IPPs would result in competition for generation which should result in lower costs of power production. However, other factors such as taxes, which are not always paid by utilities, are artificial differences which can distort a true economic circumstance and lead to a less than optimum overall result.

- An open market created by wheeling within and between Canadian provinces and between Canada and the U.S. would result in many benefits, including improved reliability, varied unit sizes, locations and sources of energy, smoothing of peaks across time zones, and good matching of specific generation and loads.

TransAlta Utilities

- Independent power production is another alternative for utilities to meet the needs of their consumers.
- The purchase of power from an independent power producer is not a factor in interprovincial cooperation unless the independent power producer in one province wishes to sell to a party in another province, necessitating wheeling arrangements by intervening utilities.
- Interconnection of independent power producers' generation, as with any facility, must be done in such a way that it will not have negative impacts on the system to which it is connected, or on any other systems which are in turn interconnected.

Alberta Power

- Independent power production provides another alternative for utilities to meet the needs of their consumers. Purchases from independent power producers are not a factor in interprovincial cooperation unless the independent power producer in one province wishes to sell to a party in another province. Such a transaction would require appropriate arrangements for use of the transmission systems between the producer and the purchaser.

Edmonton Power

- In general, independent power production is not a factor in facilitating interprovincial cooperation. Independent producers may require interprovincial cooperation beyond the existing levels if they arrange to sell to markets outside

their own province. A uniform policy with respect to independent power producers may help in advancement of independent power production. Toward this end, there is a provincial generation policy review underway looking at the potential for, and regulatory barriers to, cogeneration and generation from waste.

SaskPower

- Non Utility Generators (NUGs) may increase the export capabilities of their province by building new production facilities when a provincial utility is unable to do so. However, if the utility has surplus generation, increased export competition may reduce utility revenues and hurt the provincial customers who pay the electricity bills.
- NUGs will have little impact on utility planning as NUG planning horizons are much shorter, and utilities will likely arrange for new supply in advance of any NUG proposals from neighbouring utilities.

Ontario Hydro

- Ontario Hydro may be interested in purchasing western fuel-by-wire from an IPP, but Ontario Hydro would rather do business with a major provincial utility or energy company (more stability, responsibility to execute agreements).
- If Ontario Hydro bought from an IPP, the IPP would have to provide good assurances of reliability and continuity of supply, and the IPP would be responsible for obtaining all regulatory approvals outside Ontario.
- The government could help facilitate wheeling arrangements by assisting utilities (e.g., by timely reviews, risk sharing) to overcome concerns they have about wheeling (e.g. cost, reliability, lead time, priority issues).
- Several of the NUG proposals in Ontario are corporately backed by an electric utility in western Canada; this adds credibility to the proposals and is another form of interprovincial cooperation.

Hydro-Québec

- As independent power production is currently integrated into the production of Hydro-Québec's system, IPPs can do little to facilitate interprovincial cooperation.

New Brunswick Power

- It has been demonstrated that IPPs can provide generation to a utility at competitive rates; however, N.B. Power does not have any experience where IPPs could "facilitate" interprovincial cooperation in electricity production.
- Possible scenario: an IPP in a province that does not need additional electricity could develop a generation project and sell it to another province.

Nova Scotia Power

- IPPs will have only a very minor role.
- The only role for IPPs in interprovincial cooperation would be where the IPP wishes to sell power outside its province and thus requires a wheeling agreement from its provincial utility.

5.6 Actions to Encourage Future Cooperation Initiatives

The utilities were asked to identify what actions by: (i) utilities; (ii) the federal government; and (iii) provincial governments could assist the realization of future initiatives. The utilities' responses are summarized in Table 5.3.

5.6.1 Actions by Utilities

Four utilities were of the opinion that policies should be developed on transmission access (wheeling).

Six utilities felt that future initiatives should be developed by direct negotiations among utilities.

Table 5.3

Proposed Assisting Actions For Future Initiatives (Responses to Question 10)	Responding Utility										
	BCH	COM	TAU	SP	MH	OH	H-Q	NBP	NSP	ME	NLH
By Utilities:											
Policies should be developed on transmission access (Wheeling)		X	X			X				X	
Future initiatives should be developed by direct negotiations among utilities				X	X	X	X	X	X		
Maximize use of environmentally preferable sources						X					
Increase use of interconnections to enhance security of supply						X					
Readiness to make beneficial equity investments in other provinces						X					
H-Q should agree to wheel future Labrador power or to other satisfactory disposal.											X
By the Federal Government:											
Policies should favour cooperation and transmission access to all utilities				X	X						
Should act as a facilitator at the request of utilities possibly providing additional benefits in financing and regulation			X		X	X					
Formulate relative economics of environmental effects and measures and distribution of costs and benefits					X						
Eliminate disincentives and other obstacles						X					
Provide leadership in goal-setting, public information and promote R, D & D						X					
Provide end-use incentives						X					
Federal actions should not frustrate deregulation or raise obstacles							X				
Transmission access should not be compulsory							X				
Canada (as Shareholder) should authorize LCDC to act to develop new Labrador power.											X

Legend

BCH - B.C. Hydro/Powerex
 COM - Cominco
 TAU - TransAlta
 SP - SaskPower
 MH - Manitoba Hydro
 OH - Ontario Hydro

H-Q - Hydro-Quebec
 NBP - New Brunswick Power
 NSP - Nova Scotia Power
 ME - Maritime Electric
 NLH - N & L Hydro
 LCDC - Lower Churchill Development Corporation

Table 5.3 (cont'd)

Proposed Assisting Actions For Future Initiatives (Responses to Question 10)	Responding Utility										
	BCH	COM	TAU	SP	MH	OH	H-Q	NBP	NSP	ME	NLH
By Provincial Governments:											
Development of transmission access (wheeling) policies	X										
Adopt a broader perspective favouring wider initiatives, rather than local preferences					X						
Quebec should allow H-Q to purchase new Labrador power.											X
Newfoundland should authorize steps necessary to develop new Labrador power.											X
By Both Federal and Provincial Governments:											
Regulatory processes should be streamlined and clarified	X							X			
Policies should be harmonized					X			X			
Regulatory processes should be coordinated-overlaps eliminated	X							X			
Where governments are satisfied, minimize involvement-utilities should decide					X						
Consequences to all entities should be taken into account-national interest should be served first, if not detrimental to utility					X						
Policies should influence economic choice, not impose direction					X						
Policies should remain stable, not lengthen project time, nor add uncertainty					X			X			
Governments should require utility coope- ration, if necessary by legislative action										X	

Legend

BCH - B.C. Hydro/Powerex
 COM - Cominco
 TAU - TransAlta
 SP - SaskPower
 MH - Manitoba Hydro
 OH - Ontario Hydro

H-Q - Hydro-Quebec
 NBP - New Brunswick Power
 NSP - Nova Scotia Power
 ME - Maritime Electric
 NLH - N & L Hydro
 LCDC - Lower Churchill Development Corporation

One utility (Ontario Hydro) suggested the maximum use of environmentally-preferable sources, increased use of interconnections to enhance security of supply, and readiness to make beneficial equity investments in other provinces.

Newfoundland and Labrador Hydro made a very specific proposal regarding the wheeling, or other satisfactory disposal, of Labrador power.

5.6.2 Actions by the Federal Government

Two utilities proposed that federal policies should favour cooperation and transmission access.

Three utilities suggested that the federal government act as a facilitator at the request of the utilities and possibly provide additional incentives in financing and regulation.

One utility (Manitoba Hydro) felt that the federal government should formulate the relative economics of environmental effects and measures as well as the distribution of costs and benefits.

One utility (Ontario Hydro) proposed that the federal government eliminate disincentives and other obstacles, provide leadership in goal setting and public information, promote research and development and provide end-use incentives.

One utility (Hydro-Québec) proposed that federal actions should not frustrate deregulation nor raise obstacles and that transmission access should not be compulsory.

Newfoundland and Labrador Hydro made the specific suggestion that Canada should authorize Lower Churchill Development Corporation to act to develop new Labrador power.

5.6.3 Actions by Provincial Governments

B.C. proposed the development of transmission access and wheeling policies. Manitoba advocated the adoption of a broader perspective, favouring wider initiatives rather than local preferences.

Newfoundland and Labrador Hydro had two specific proposals: (i) that Québec should allow Hydro-Québec to purchase power from new Labrador sources; and (ii) that Newfoundland should authorize actions necessary for the development of such new power sources.

5.6.4 Actions by Both Levels of Governments

Two utilities advised that regulatory processes should be streamlined and clarified.

Two utilities suggested that government policies be harmonized.

Two utilities recommended that regulatory processes should be coordinated and overlaps eliminated.

One utility (Manitoba Hydro) made three proposals: (i) that, where governments are satisfied, their involvement should be minimized; (ii) that the consequences to all entities should be taken into account and the national interest served first, if not detrimental to the utility's interest; and (iii) that policies should influence economic choice, not impose direction.

Two utilities advised that policies should remain stable, not lengthen project time, nor add to uncertainty.

One utility (Maritime Electric) suggested that governments should require inter-utility cooperation, if necessary by legislative action.

5.7 Responses from Provincial Governments and Others.

In addition to those from electric utilities, responses to the Board questionnaire were received from:

- (i) The Attorney General of Newfoundland and Labrador
- (ii) The British Columbia Ministry of Energy, Mines and Petroleum Resources
- (iii) The Québec Ministry of Energy and Resources

- (iv) The New Brunswick Department of Natural Resources and Energy
- (v) The PEI Department of Energy and Forestry
- (vi) The Municipal Electric Association
- (vii) The North American Electric Reliability Council
- (viii) The Director of Investigation and Research Competition Act
- (ix) M.V. Spence, P. Eng.
- (x) Eugene Fytche, P. Eng.

5.8 Conclusions

There already exists in Canada a considerable degree of inter-utility cooperation, from which significant benefits are derived. Canada's electric utilities are also planning a significant amount of future inter-utility cooperation.

Such cooperation generally includes exchanges of economy energy, non-economy capacity and energy, coordinated operation, reserve sharing, maintenance scheduling, emergency support, etc. There is a very limited degree of integrated generation expansion planning. Typically, cooperative activities are carried out under interconnection agreements negotiated on a bilateral basis.

To a greater or lesser degree such cooperation is carried out where an interconnection exists between Canadian (or Canadian and United States) utilities. Perhaps the highest current degree of cooperation exists in Alberta under the auspices of the Alberta Interconnected System Power Pool, which can be described as a "tight" pool. This is, of course, an intra-provincial agreement and, as such, does not involve inter-provincial cooperation.

Wheeling is limited and generally restricted to cases where the sender and receiver are the same entity or where power is wheeled to a utility purchasing it from the wheeler's system.

Generally, utilities are in favour of developing future initiatives by direct negotiation among themselves and a number feel that they should develop policies on wheeling as BC Hydro/POWEREX is now doing.

According to some utilities the federal role should be that of providing leadership, developing favourable policies, and providing clear, streamlined, stable, and coordinated regulation. These perceptions also applied, in general, to provincial governments.



6. OPPORTUNITIES FOR FURTHER INTER-UTILITY COOPERATION IN CANADA



6. OPPORTUNITIES FOR FURTHER INTER-UTILITY COOPERATION

6.1 Introduction

The preceding chapter described the current extent of cooperation among Canadian electric utilities. The intent of this chapter is to highlight situations where there appear to be opportunities for increased cooperation leading to benefits additional to those now being realized.

It must be emphasized that reliance should not be placed on the absolute estimates of benefits shown in this chapter - instead they should be considered as giving only a very approximate indicator of the potential benefits arising from increased inter-utility cooperation.

6.2 Regional Analyses

In a recent National Energy Board staff study entitled "Comparative Costs of Generation in North America: Canadian Regional Cooperation and Development Opportunities" it was stated that any study on Canadian regional cooperation and development opportunities must, of necessity, take into account the potential for international as well as interprovincial trade opportunities. In examining such potential opportunities, five geographic regions (see Figure 6.1) were identified, within which opportunities for increased trade appeared to be practical, these are:

Region No. 1 - BC/Alberta/US Pacific Northwest/California

Region No. 2 - Saskatchewan/Manitoba/U.S. Midwest

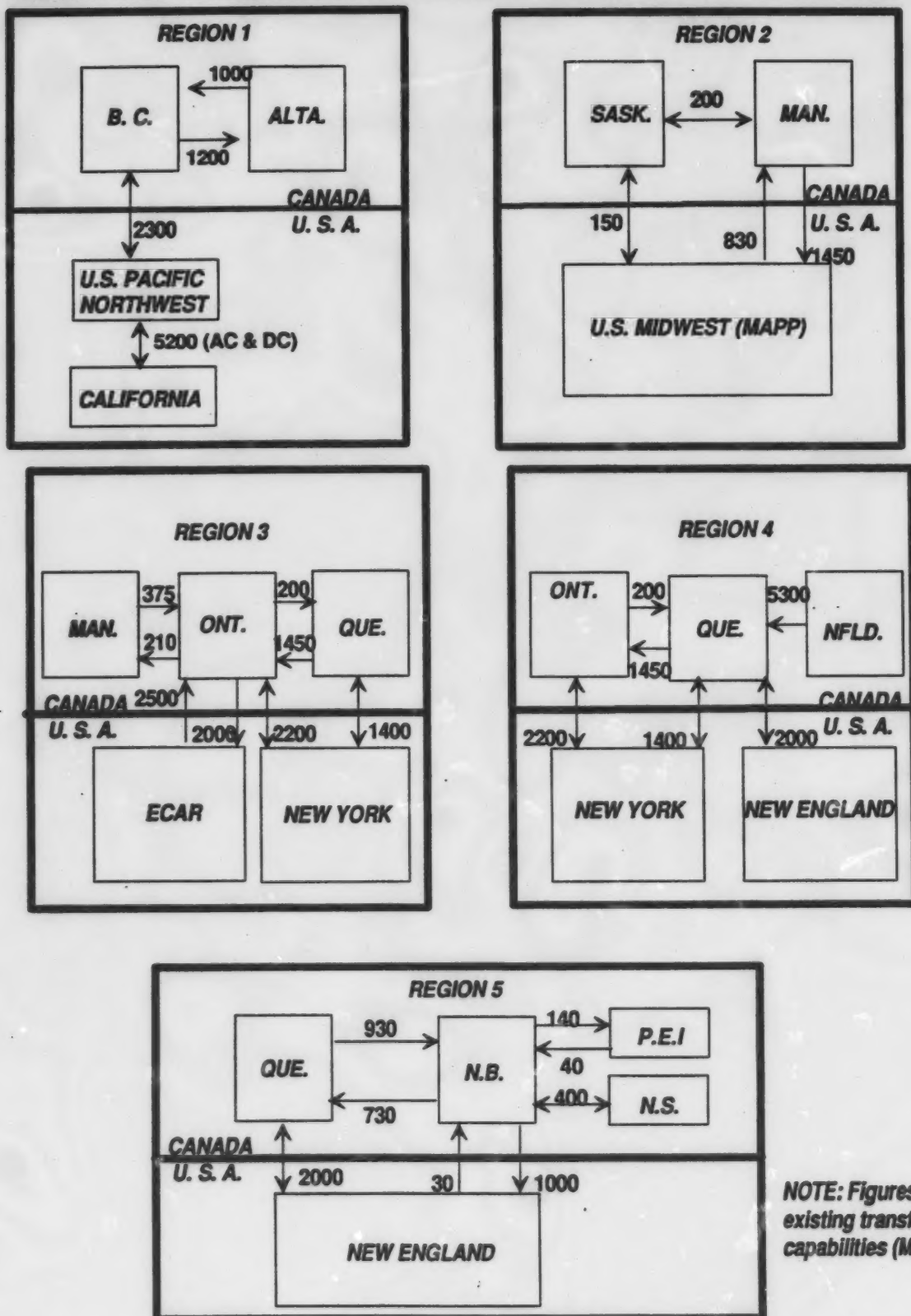
Region No. 3 - Manitoba/Ontario/Québec/New York/ECAR

Region No. 4 - Ontario/Québec/Newfoundland/New York/New England

Region No. 5 - Québec/New Brunswick/PEI/Nova Scotia/New England

Within each region, estimates were made of the levelized unit energy costs (LUECs) of new generation and associated transmission facilities in each province and selected area of the U.S. Corresponding unit fuel costs were also calculated. At the same time, corresponding estimates were made of annual capacity requirements (ACRs). The information on which the analyses were based was obtained from the utilities, and pertains generally to the year 1990. Although the plans and estimates made at that time

FIGURE 6.1
REGIONS USED TO ASSESS COOPERATION AND DEVELOPMENT OPPORTUNITIES



NOTE: Figures show existing transfer capabilities (MW)

by the utilities may have changed to some extent, this should not affect in any meaningful way the order of magnitude of the potential benefits from further cooperation that were determined.

The estimates made of LUECs, ACRs and unit fuel costs are presented in Figures 6.2, 6.3 and 6.4, respectively. These were used to identify opportunities for trade among provinces and areas of the U.S. within each of the five regions, starting in the year 2000.

6.2.1 Region No. 1 - British Columbia /Alberta/US Pacific Northwest/California

British Columbia, Alberta, the Pacific Northwest and the Pacific Southwest, particularly California, form a natural development region. This region is part of the Western Systems Coordinating Council (WSCC) which is one of nine regional councils making up the North American Electric Reliability Council (NERC). The WSCC area extends from the Pacific to the Prairies (i.e. in Canada up the Alberta/Saskatchewan border). Region No. 1 also forms part of the Western Interconnection and operates separately from the Eastern Interconnection which stretches from the Prairies to the Atlantic.

Figures 6.2, 6.3, 6.4 and 6.5 show the LUECs of the generating and associated transmission facilities, the corresponding ACRs and unit fuel costs for each province and the state of California, as well as the existing interconnection transfer capacities between the systems. This study focused only on California as it appeared to be the most lucrative market for Canadian electricity exports. However, it is recognized that there is also a growing market for electricity export into the Pacific Northwest. In addition, Canadian opportunities in the California market may be hindered by competition from the Desert Southwest and Mountain regions of the U.S. Also shown in Figure 6.5 is the interprovincial and international market potential for electricity trade within the region.

From these figures the following observations can be made:

- Natural gas-fired generation costs in California are about three times the cost of Alberta's subbituminous coal-fired generation. In addition it is twice as costly when compared with B.C.'s Site "C" hydro generation. These margins may be somewhat reduced if other supply alternatives in B.C. (i.e. coal-fired generation) are utilized.

FIGURE 6.2

Nominal LUEC in mills/KW.h* for selected North American generating Facilities for in service in the year 2000. Based on average generation for hydro, and base load for all other thermal plants (i.e. 80% CF).

* Expressed in Canadian \$ in the year 2000.

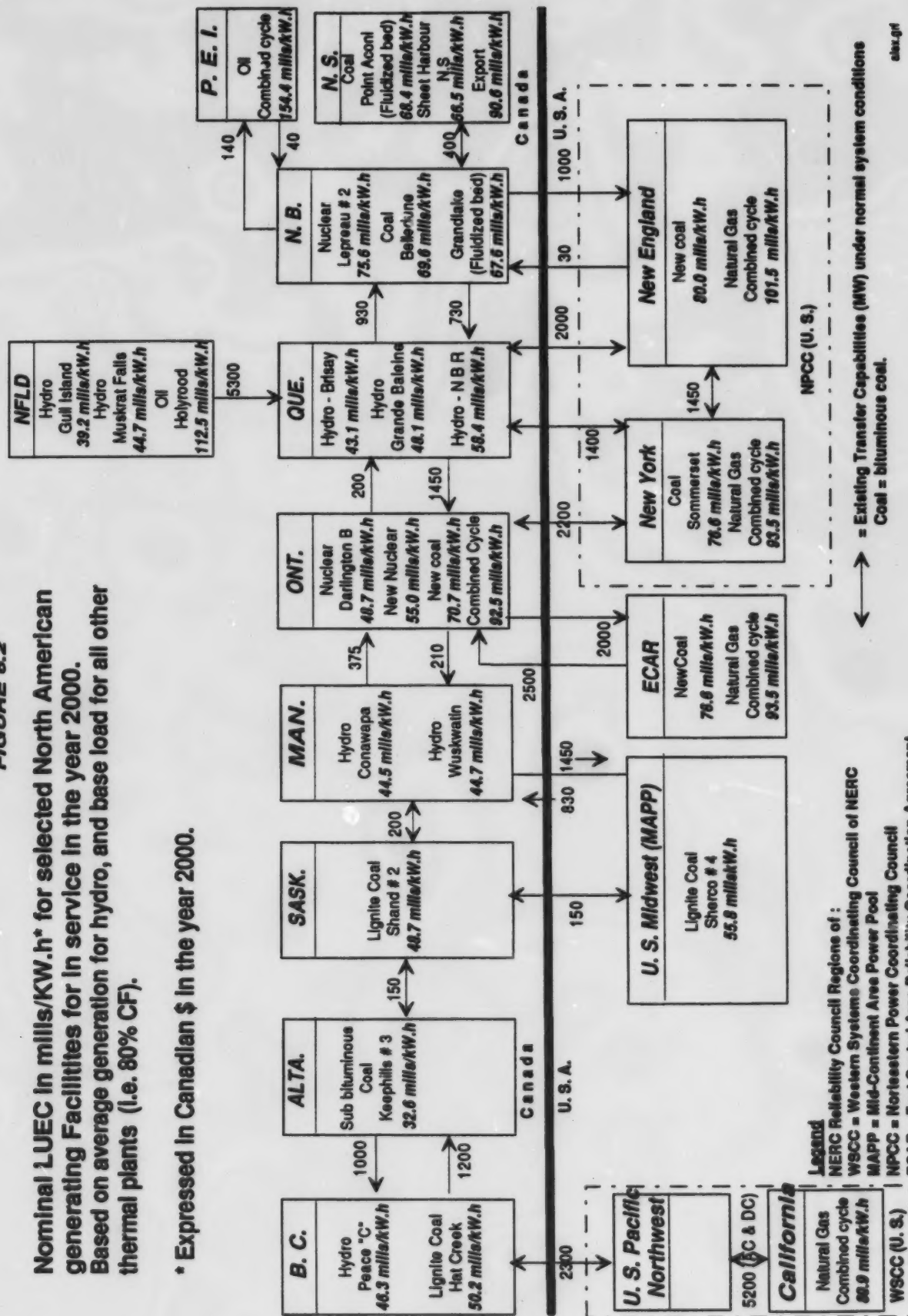


FIGURE 6.3

GENERATION SUPPLY GROWTH POTENTIAL IN CANADA AND SELECTED U.S. STATES BY YEAR 2000

Note : (1) assume 2 % / year load growth
(2) hydro systems reserve of 12 %
(3) thermal systems reserve of 20 %

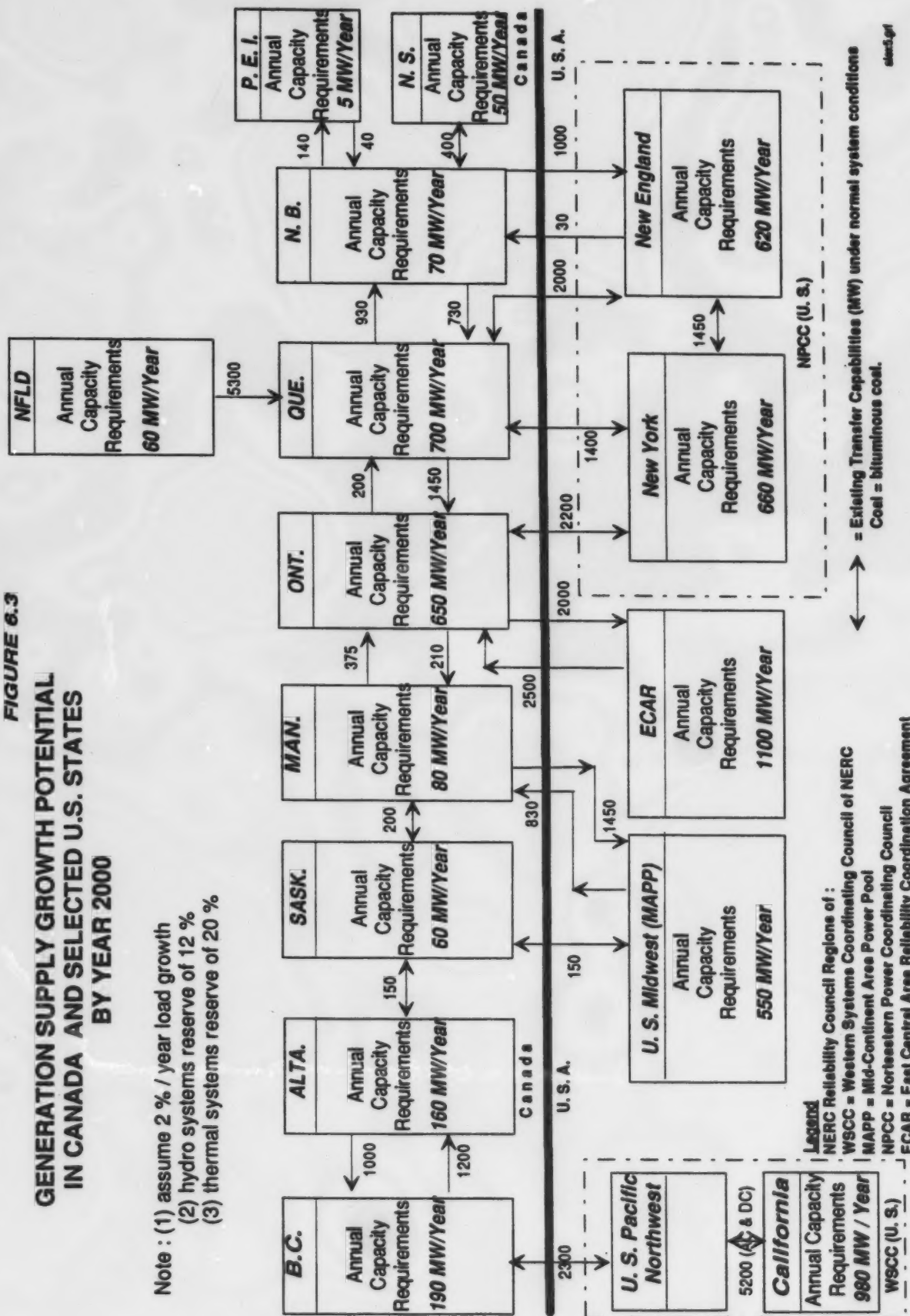


FIGURE 6.4

Nominal Fuel LUEC in mills/KW.h* for selected North American generating Facilities for in service in the year 2000
Based on average generation for hydro, and base load for all other thermal plants (i.e. 80% CF).

* Expressed in Canadian \$ in the year 2000.

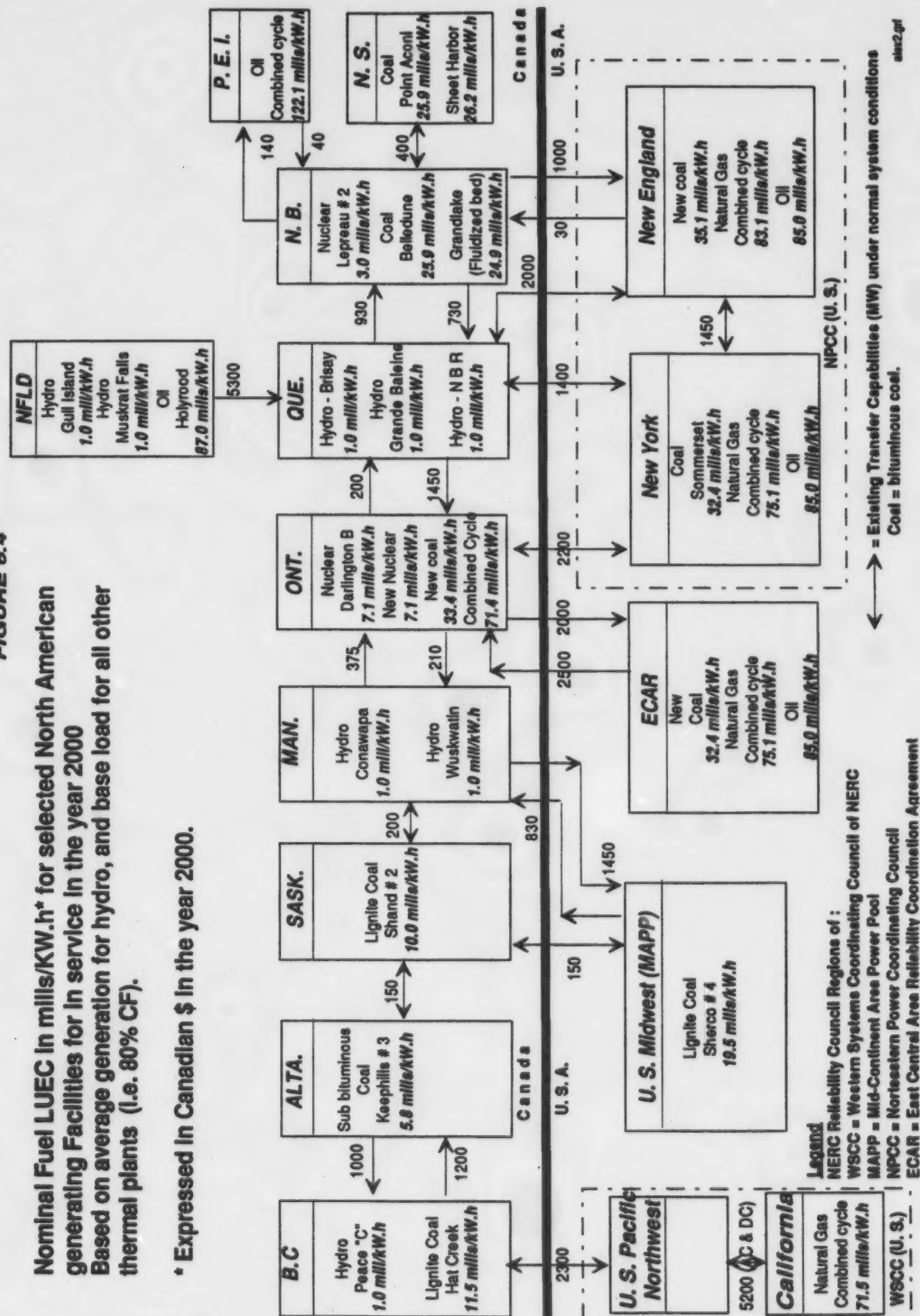
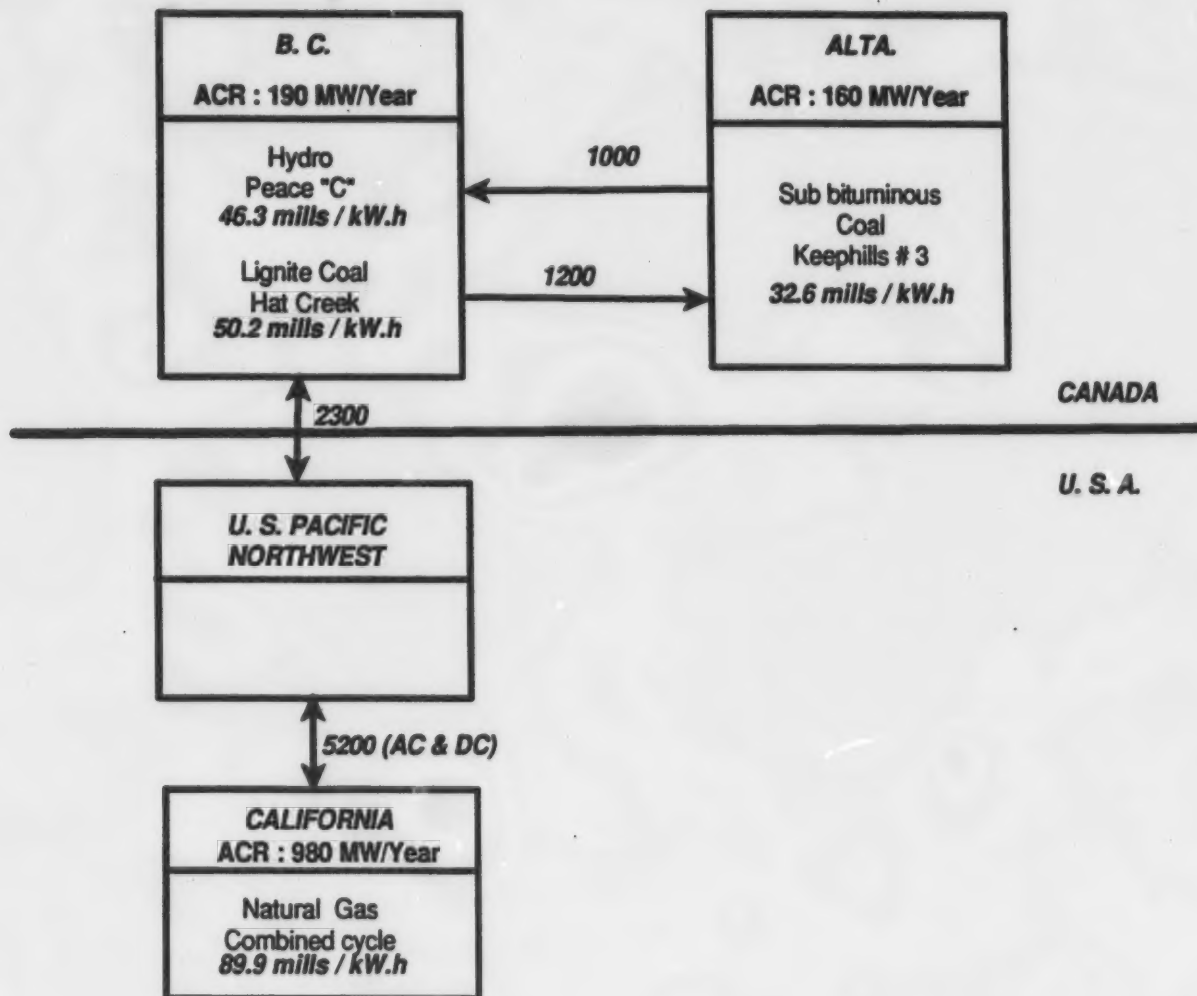


FIGURE 6.5
COOPERATION AND DEVELOPMENT OPPORTUNITIES FOR
REGION 1
ACR : Annual Capacity Requirements



MARKET POTENTIAL FOR ELECTRICITY TRADE

Type of Trade	Negotiating Parties		L U E C mills / KW.h		Negotiating Margin
INTERPROVINCIAL	B. C.	ALT.	46	32	14 mills / kW.h
INTERNATIONAL	B.C.	CALIF	46	90	44 mills / kW.h
	ALT.	CALIF	32	90	58 mills / kW.h

- Even adding the cost of transmission upgrades on the U.S. Pacific North/South intertie to transport Canadian electricity to California, it appears that Canadian exports will be more competitive than any U.S. alternative supplies in that market.
- If Alberta could access the California market, via the B.C. and the Bonneville Power Authority (BPA) systems, it would offer that province a much more lucrative trade than dealing only with B.C.
- Although Alberta's generation is 50 percent less costly than B.C.'s, significant transmission upgrades between Alberta and B.C. will be required to bring the Alberta supply to the B.C. market. However, opportunities may exist for some form of coordinated development, and BC Hydro and TransAlta (representing the utilities of the AIS) have studied this potential.
- Alberta's predominantly thermal system with its low generation costs of some 6 mills/kW.h provides significant low-cost surplus energy which can be coordinated with the capacity available on the energy-constrained BC Hydro system. Potential opportunities thus exist for hydro/thermal coordination of the combined resources of the two provinces.
- Annual capacity requirements for the combined provinces of B.C. and Alberta are estimated to be about 350 MW/yr. This means that about 1000 MW of plant may be required every three years to meet the expected increase in demand. Opportunities therefore appear to exist for the coordination and planning of the generation programs in the two provinces.
- Staggering of generation additions between the two provinces, reinforcing the interprovincial ties, etc. through the joint planning of generation and transmission developments could provide significant benefits to both provinces. In addition, any potential capacity and energy surpluses that may result from such developments could be better coordinated to maximize the revenues generated from export sales.
- Short-term firm exports by BC Hydro with energy firmed-up by Alberta could enable higher valued exports to be made into the California market.

- The marginal cost generation in California is combined cycle generation using relatively high-cost natural gas. This allows increased opportunities for short-term economy energy exports by BC Hydro or by TransAlta via BC Hydro's network. (Both types of exports are now taking place as transmission access opportunities arise on the BPA North/South interties).
- B.C. has formed the POWEREX Pool Operation (PPO). PPO is a marketing operation that will serve short-term bulk electricity markets within and outside B.C., including Alberta and the western United States. PPO will facilitate short-term electricity transactions to realize competitive opportunities and efficiency gains in the bulk power market for the benefit of B.C.
- B.C. and Alberta are winter peaking systems and consequently have surplus capacity during the summer periods. The same is true for US utilities in the Pacific Northwest. Utilities in California on the other hand are summer peaking systems with surplus capacity during the winter months. Potential opportunities therefore exist for summer/winter seasonal diversity exchanges between utilities in B.C., Alberta and the Pacific Northwest and those in California. Even if U.S. utilities in the Pacific Northwest have priority over Canadian utilities in such diversity trade, there still appear to be opportunities for B.C. and Alberta to take advantage of the remaining potential seasonal trade.
- In lieu of seasonal diversity exchanges there might also be potential for long-term summer sales (i.e. from May to Oct.) by B.C./Alberta utilities into the California market (if Canadian utilities cannot be assured of capacity return from California during the winter periods).
- If BC Hydro and/or Alberta can capture 20 percent of the California market it will mean on average 200 MW/yr of long-term firm exports.
- To capture such a high share of the US market may require B.C. and Alberta to pool their resources. For example, a firm export sale to California of 1000 MW for a 30-year period would only satisfy that state's growing demands for one year. A combination hydro/thermal export deal using B.C.'s hydro and Alberta's

thermal resources would provide both B.C. and Alberta with substantial benefits as well as shared risks.

- Barriers to increased international trade exist because the Bonneville Power Authority (BPA) can restrict the transmission of Canadian exports to the California market via BPA's North/South intertie.
- BC Hydro and BPA are negotiating to provide B.C. with greater transmission access in return for certain concessions to BPA.

6.2.2 Region No. 2 - Saskatchewan/Manitoba/US Midwest

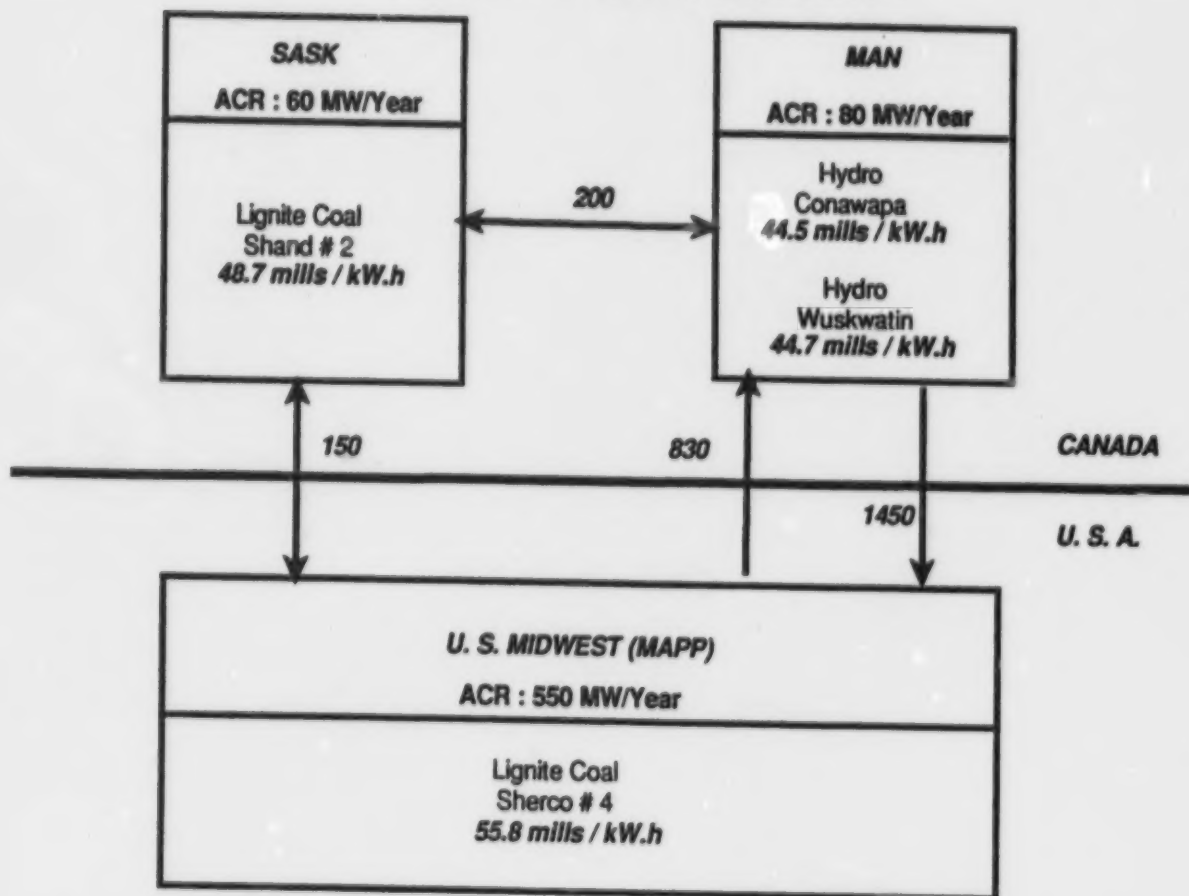
Saskatchewan, Manitoba and the US Midwest form a natural development region. This region comprises the NERC Mid Continent Area Power Pool (MAPP) and is part of the Eastern Interconnection.

Figures 6.2, 6.3, 6.4 and 6.6 show the cooperation and development opportunities for this region from which the following observations can be drawn:

- As Saskatchewan's lignite generation costs are very similar to Manitoba's hydraulic generation costs, the opportunities for regional development in these two provinces appear limited.
- Both provinces are geographically very large with low annual capacity requirements. Therefore any developments on a regional basis may require expensive long-distance, high-capacity interties to reinforce the existing ties. These additional capital costs would create significant barriers to greater regional development.
- However, opportunities for joint planning may still exist which would allow for:
 - (i) the staggering of generation in each province to serve the joint provincial demands more economically.

FIGURE 6.6
COOPERATION AND DEVELOPMENT OPPORTUNITIES FOR
REGION 2

ACR : Annual Capacity Requirements



MARKET POTENTIAL FOR ELECTRICITY TRADE

Type of Trade	Negotiating Parties		L U E C mills / KW.h		Negotiating Margin
INTERPROVINCIAL	MAN	SASK	45	49	4 mills / kW.h
INTERNATIONAL	MAN	U.S. MIDWEST	45	56	11 mills / kW.h
	SASK	U.S. MIDWEST	49	56	7 mills / kW.h

- (ii) greater generation reserve sharing to reduce the capacity margins required for planned and forced outages of generating facilities within the existing tie-line limits.
- Generating costs in Manitoba are estimated to be about 25 percent less than the best alternatives (i.e. lignite plants) in the U.S. Midwest.
- This comparative advantage does not appear to be large enough to penetrate the U.S. Midwest market for the following reasons:
 - (i) U.S. utilities may require at least a 20 percent (i.e. 6 mills/kWh) price discount (e.g. this was the basis for the Manitoba Hydro - Northern States Power 500 MW sale from Limestone).
 - (ii) Additional intertie costs could absorb the remaining 5 percent negotiating margin (i.e. 3-4 mills/kWh).
- Manitoba was able to negotiate a 500 MW long-term firm sale from the output of Limestone with Northern States Power (NSP). However the cost of Limestone was significantly less than Conawapa.
- Manitoba is a winter peaking system while some U.S. Midwest utilities are summer peaking systems. Thus opportunities for summer/winter diversity exchanges do exist. In fact Manitoba now has 300 MW of diversity sales with NSP and is negotiating to increase that amount to 500-700 MW starting in the mid 1990's with NSP and other U.S. utilities.
- In parallel with negotiations with the U.S., Manitoba has been negotiating with Ontario Hydro. It has recently signed a 1000 MW long-term sale from the Conawapa plant which is expected to come into service in the late 1990's.
- With this sale, it is unlikely that Manitoba would be interested in any further large long-term firm exports deals with utilities in the U.S. Midwest.
- Joint hydro/thermal coordination opportunities exist which would allow Manitoba to firm-up its capacity by accessing Saskatchewan's thermal energy

surpluses. Such opportunities may be limited, however, because of the limited availability of surplus energy from Saskatchewan.

- Manitoba Hydro and NSP have concluded a firm energy back-up agreement which allows Manitoba to call on up to 1500 GW.h in any one year to firm up its dependable capacity supply when stream flows are low.
- The 1500 MW international tie between Manitoba and the U.S. Midwest is large enough to transmit all firm capacity export commitments in addition to making interruptible energy sales when opportunities exist. The marginal fuel costs of 19 mills/kW.h in the U.S. Midwest provides significant economic incentives for Manitoba to sell any surplus hydro it has available.
- During low water years this high-capacity international tie also enables Manitoba to import electricity (e.g. in 1987-88) to meet its domestic demands.

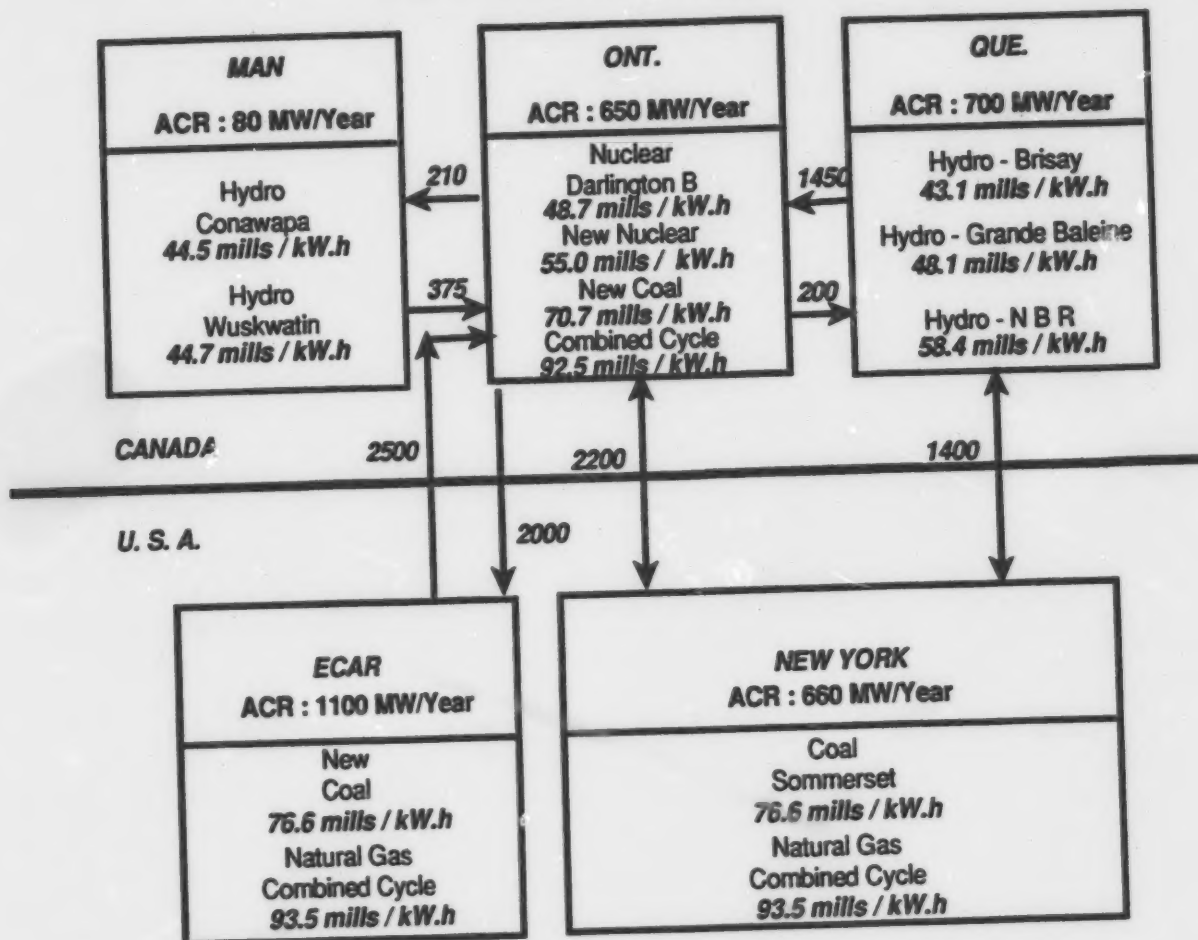
6.2.3 Region No. 3 - Manitoba/Ontario/Québec/New York/ECAR

Although Ontario, Québec, New York and Michigan form a natural development region, the recently concluded 1000 MW long-term purchase/sale agreement between Ontario and Manitoba now also places Manitoba within this region. This region comprises parts of the MAPP and the Northeast Power Coordinating Council (NPCC), as well as part of the East Central Area Reliability Coordination Agreement (ECAR).

Figures 6.2, 6.3, 6.4 and 6.7 show the cooperation and development opportunities for this region. From an examination of these figures, the following observations can be made:

- Ontario's least-cost long-term economic alternative, by far, appears to be nuclear generation. It is about 30 to 40 percent less costly than new coal-fired generation and is decidedly more economic than combined cycle generation using natural gas. It is recognized that the planning period for nuclear plants is currently estimated to be about 15 years so that the earliest in-service date for such plants would be about 2005, and not 2000 (which was assumed in the LUEC study). Nevertheless, because of the comparative nature of this analysis, the calculated benefits are not expected to change significantly with changes in in-service dates.

FIGURE 6.7
COOPERATION AND DEVELOPMENT OPPORTUNITIES FOR
REGION 3
ACR : Annual Capacity Requirements



MARKET POTENTIAL FOR ELECTRICITY TRADE

MARKET POTENTIAL FOR ELECTRICITY TRADE					
Type of Trade	Negotiating Parties		L U E C mills / kW.h		Negotiating Margin
INTERPROVINCIAL	ONT.	MAN	55	45	10 mills / kW.h
	ONT.	QUE	55	48	7 mills / kW.h
INTERNATIONAL	ONT.	NY	55	77	22 mills / kW.h
	QUE.	NY	48	77	29 mills / kW.h

Base load hydro generation costs in Manitoba are similar to Ontario's nuclear power costs from the Darlington B nuclear power plant and are only marginally less expensive than new nuclear units in Ontario. It thus appears that considerations other than tangible economics played a large role in the recent 1000 MW purchase/sale agreement between Ontario and Manitoba. These considerations, including secondary economic effects, were:

- (i) Increased diversity of supply for Ontario.
- (ii) Greater support and increased reliability for loads in northwest Ontario.
- (iii) Ontario's need to reinforce its ties between the northwest and central systems by the early 2000's. It is thus possible with only an additional transmission outlay of \$80-100 million to also increase its interprovincial ties with Manitoba from 375 MW to 1500 MW in order to support the 1000 MW Conawapa purchase.
- (iv) The reinforced interprovincial ties will also allow Manitoba Hydro surplus energy, over and above the contract amounts, to penetrate the more lucrative southern Ontario market where Ontario's long-term marginal cost of generation using coal is estimated to be 33 mills/kW.h as opposed to the U.S. Midwest market where the comparable costs are about 19 mills/kW.h. Any economic benefits from such interprovincial trade would be shared between the two provinces.

The Manitoba-Ontario agreement thus is a classic example of the cooperation that is possible between provinces to promote greater interprovincial electricity trade.

Because Ontario's nuclear generation costs are estimated to be comparable to the costs of Québec's potential hydraulic generation at Grande Baleine and Nottaway-Broadback-Rupert, there appears to be little opportunity for large long-term firm purchase and sales agreements which would increase interprovincial electricity trade between the two provinces. Negotiations did take place in the 1987-89 period but have since broken off, generally because the price quoted by Québec was more than Ontario was prepared to pay.

- At present the main Ontario and Québec systems are separated electrically. Electricity transfers are now only possible by physically isolating Québec generation and connecting it to the Ontario network and vice versa. This arrangement allows some 1450 MW of Québec generation to be transferred to Ontario, but only 200 MW of Ontario generation to be isolated for Québec's needs.
- Québec had significant hydraulic surpluses for many years, and Ontario was able to gain access to this energy with minimum additional capital expense to its transmission system by using the network arrangements described above.
- This situation has now changed. Québec's hydraulic surpluses are coming to an end, while Ontario, if it continues to build base load nuclear generation, may have significant amounts of relatively low-cost nuclear energy (i.e. 7-8 mills/kW.h) during off peak periods of the day.
- There thus appear to be "energy banking" opportunities similar to arrangements that now exist between Québec and the New England Power Pool (NEPOOL). Energy banking allows lower marginal cost U.S. electricity to be imported by Québec during off-peak periods, stored by displacement in Québec's vast hydraulic reservoirs and be exported or "returned" during peak periods when NEPOOL's marginal cost of generation is high.
- Energy banking between Ontario and Québec, however, will require the two systems to be electrically connected, via high capacity direct current links in this case, to enable large transfers of electricity to take place in both directions.
- Strengthening the Ontario-Québec interprovincial ties will also allow a wide spectrum of other types of transactions to take place for mutual economic and reliability benefits. It is understood that the two utilities are examining this possibility.
- Because Ontario and Québec are winter peaking systems while ECAR and New York are summer peaking systems, opportunities exist for winter/summer seasonal diversity exchanges and summer sales. At present Québec has an 800

MW long-term seasonal diversity exchange with the New York Power Authority, however additional potential trade of these types may be possible.

- Although both Ontario and Québec appear to have a decided economic cost advantage over generation in New York, Ontario's stated policy is not to build for exports, unlike Québec which supports and encourages the advancement of its generation program for export purposes.

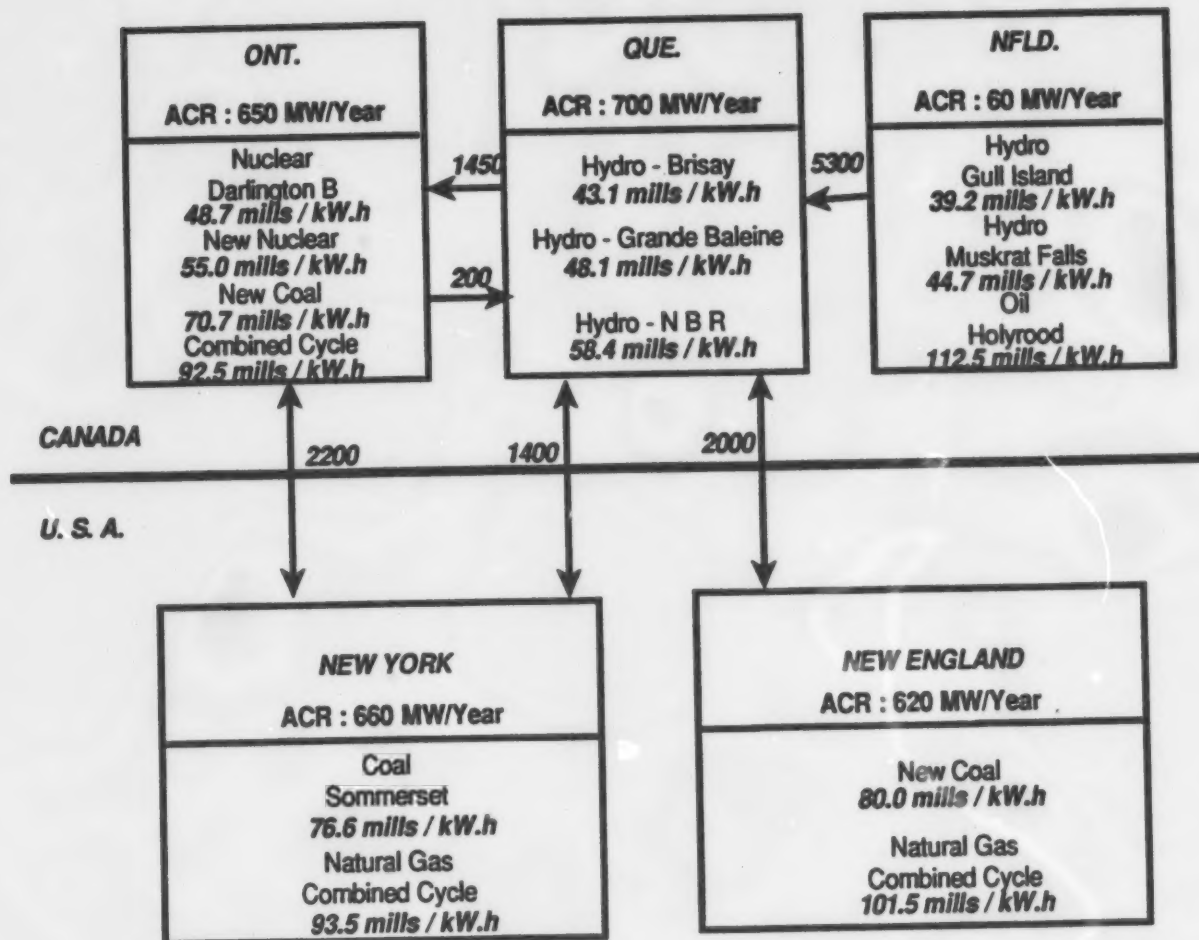
6.2.4 Region No. 4 - Ontario/Québec/Newfoundland/New York/New England

Ontario, Québec, Newfoundland and Labrador, New York and the New England states form a natural development region. All these provinces and states except Newfoundland and Labrador are part of NERC's NPCC region.

Figures 6.2, 6.3, 6.4, and 6.8 show the cooperation and development opportunities for this region. Examination of these figures shows that:

- New England is an attractive market for Québec. Québec has negotiated a 500 MW firm export sale to the Vermont Joint Owners (VJO). Québec also negotiated a 1 000 MW firm export sale to the New York Power Authority (NYPA) but this was subsequently cancelled by NYPA which cited economic reasons and environmental concerns over development of new hydro projects in the Baie James area. Nevertheless, the long-term prospects for firm exports from Québec to N.Y. and/or N.E. remain.
- The potential development of the Gull Island hydro project in Labrador appears to be the most economic new generation in Canada at 39 mills/kW.h. Muskrat Falls at 45 mills/kW.h is also very high in the economic ranking of Canadian generation.
- The comparable cost of oil-fired generation on the island of Newfoundland is estimated at 112 mills/kW.h. This provides a powerful incentive for the exploitation of the Labrador hydraulic resources to serve the Island's increasing demand.

FIGURE 6.8
COOPERATION AND DEVELOPMENT OPPORTUNITIES FOR
REGION 4
ACR : Annual Capacity Requirements



MARKET POTENTIAL FOR ELECTRICITY TRADE

Type of Trade	Negotiating Parties		L U E C mills / kW.h		Negotiating Margin
INTERPROVINCIAL	QUE	NFLD	48	39	9 mills / kW.h
	ONT	NFLD	55	39	16 mills / kW.h
INTERNATIONAL	NFLD	NY	39	77	38 mills / kW.h
	QUE	NY	48	77	29 mills / kW.h
	QUE	NE	48	80	32 mills / kW.h

- The combined capacity of Gull Island (2200 MW) and Muskrat Falls (820 MW) is 3000 MW. This capacity is too large for Newfoundland to readily absorb on its own system as the total domestic demand, even by the year 2000, is not expected to reach 2500 MW, while the annual capacity requirements are estimated to be less than 60 MW/yr.
- Power from the potential hydro developments located in Labrador must be transmitted to the Island via an undersea HVDC high capacity cable across the Strait of Belle Isle.
- A potential fast-track development of Gull Island and Muskrat Falls might be to consider long-term firm sales to systems large enough to absorb the full output of these plants. These markets are Québec, Ontario, the Maritimes, New York and/or New England.
- It should be noted that the LUECs for the various supply sources also include transmission costs to bring the supply to the market. In the case of Newfoundland's generation costs, it includes the incorporation of a HVDC link which is required to transmit the power from Labrador to the Island's load centre at St John's. The costs of Gull Island to serve either the Ontario, Québec or the NY and NE markets may be somewhat lower than the costs to serve the Island since the respective costs of transmission to serve each of these external markets are likely to be lower than the cost of the HVDC link to the Island.
- There appear to be very limited opportunities to conclude a long-term sale/purchase agreement between Québec and Newfoundland as the negotiating margin appears to be quite small, although the delay in new hydro development in Québec could alter this situation.
- However, as in the Ontario/Manitoba case, Québec may find it more advantageous to reach a deal to purchase all or part of the output of Gull Island rather than to build, particularly if new hydro development in the province is unduly delayed. Some reasons for choosing this option include:
 - (i) Need for more generation to support Québec's eastern system.

(ii) Diversity of supply.

(iii) Faster completion for Gull Island as opposed to Grande Baleine to serve Québec's increasing demand.

- It is understood that negotiations between Québec and Newfoundland are continuing.
- Negotiating margins between Newfoundland and Ontario appear to be significant. At one time there was considerable interest in a three-party deal which would include Ontario, Québec and Newfoundland. However, this has subsided because Québec indicated that it was interested in the full output of the plants in Labrador.
- Obviously the negotiating margins between Newfoundland and New York and/or NE provide a very lucrative market for Gull Island and Muskrat Falls, even considering all the additional transmission in Québec (paid for by Newfoundland) which would be needed to supply the NY or NE markets.
- Exploiting Labrador hydro resources for export purposes raises several major concerns. These include:
 - (i) Transmission access through the Québec network to reach NY.
 - (ii) Potential loss of sales for Québec that may result from a Newfoundland-NY/NE deal.
 - (iii) Federal/provincial jurisdiction.
- Even considering these apparent barriers, it might be possible for Québec and Newfoundland to reach an agreement. Such an agreement might include the building of Gull Island and/or Muskrat Falls to serve part of Québec's future requirements as well as the export market. A combined deal would provide Newfoundland with increased economic benefits through export sales while simultaneously providing Québec with electricity at prices which are competitive with Québec's best alternative.

6.2.5 Region No. 5 - Québec/New Brunswick/PEI/NovaScotia/NewEngland

Québec, New Brunswick, Prince Edward Island, Nova Scotia and the New England states form a natural development region. All these provinces and states, except PEI, are members of the NPCC region. In this appraisal Newfoundland was confined to Region No. 4 because from a historical perspective, Newfoundland has traditionally dealt with utilities in that region.

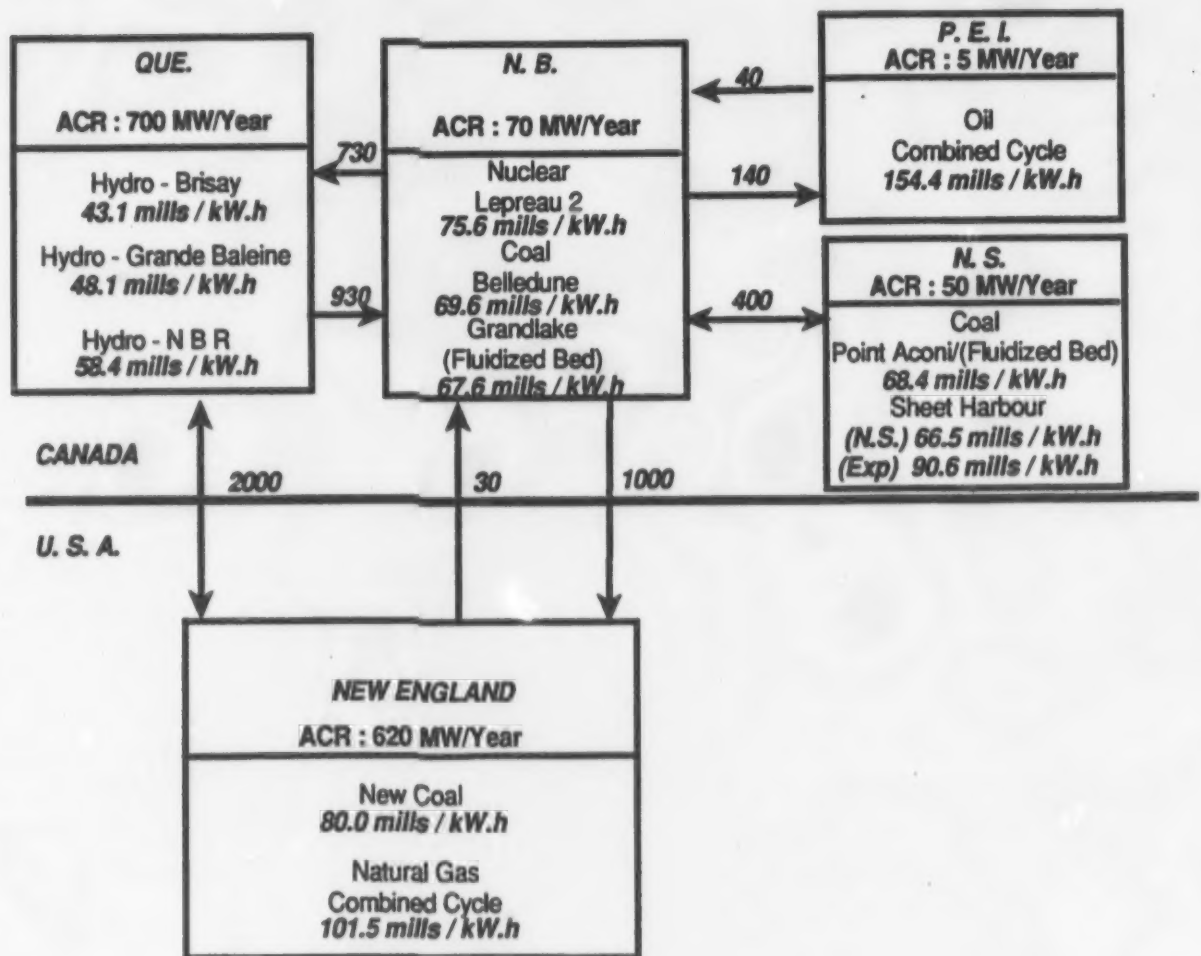
Figures 6.2, 6.3, 6.4, and 6.9 show the cooperation and development opportunities for this region from which the following observations may be drawn:

- NB is strategically located geographically. It has direct ties to all other systems in the region.
- Both NS and PEI can only gain access to the Québec or New England markets by an overland route through NB or via undersea cables.

The interprovincial transmission between Québec and New Brunswick, rated at 900 MW, allows New Brunswick to access surplus hydraulic energy from Québec to displace NB's higher-cost oil and coal-fired generation. NB and Québec have conducted such trade for many years, providing both provinces with economic benefits.

- Québec has recently decided that it needed additional peaking capacity, in the period starting in 1991, particularly to support its loads in the Gaspé region.
- Instead of building in-province peaking capacity, Québec concluded a long-term 20-year purchase agreement with New Brunswick starting in 1991. The agreement calls for a total of 400 MW to be made available by advancing the installation of combustion turbines in the NB system.
- The existing ties are sufficiently strong in the east to west direction (i.e. 700 MW) to support these purchases without new transmission.

FIGURE 6.9
COOPERATION AND DEVELOPMENT OPPORTUNITIES FOR
REGION 5
ACR : Annual Capacity Requirements



MARKET POTENTIAL FOR ELECTRICITY TRADE

Type of Trade	Negotiating Parties		L U E C mills / kW.h		Negotiating Margin
INTERPROVINCIAL	NB	QUE	68	48	20 mills / kW.h
	NB	PEI	68	154	86 mills / kW.h
	QUE	NS	48	67	19 mills / kW.h
	QUE	PEI	48	154	106 mills / kW.h
INTERNATIONAL	NB	NE	68	80	12 mills / kW.h
	QUE	NE	48	80	32 mills / kW.h
	NS (Exp)	NE	91	80	9 mills / kW.h

- This is another good example of the cooperation possible between provinces to promote greater interprovincial joint developments and to enhance electricity trade.
- NB's ties to Prince Edward Island are rated at 200 MW. However the actual transfer is limited because the PEI peak load is only about 140 MW. These transfers have historically enabled PEI to purchase not only long-term firm capacity (i.e. 20 MW from the Dalhousie plant) but also to make economy energy purchases to displace the Island's very high incremental cost of generation. In fact, total purchases from New Brunswick have provided 85 to 95 percent of the Island's electricity needs. This situation is expected to continue in the future.
- Although about 400 MW of tie capacity exists between NB and NS, there have not been any long-term firm purchase/sale agreements between the two provinces. In general, utility trade has been of an economy energy nature, ranging between 200 to 650 GW.h/year for the period 1984 to 1988. Traditionally, such trade has not been large for the following reasons:
 - (i) Both NB and NS generation at the margin is either oil or coal. As a result, interchange opportunities appear limited.
 - (ii) When available, Québec surpluses were used first by NB to displace its own high-cost generation, leaving any remainder for sale to NS.
- The prospect of diminished Québec energy surplus in the future may create more opportunities for NB-NS electricity trade.
- Because NB's hydro plants have limited storage, considerable surplus off-peak energy exists during the spring freshet months of the year. During this period, Nova Scotia has purchased surplus hydraulic energy to displace its more-costly fossil-fired generation. Such trade is expected to continue in the future.
- New England has been, and continues to be, an important export market for NB for both long-term firm power sales (e.g. participation in the Colsen Cove oil-fired and Point Lepreau nuclear plants), as well as for short-term sales of

economy energy and other types of electricity exports pursuant to its several contracts and interconnection agreements with electric utilities in New England.

- On several occasions NB has stated that its purchase and sale transactions with neighbouring utilities have allowed it to lower electricity prices to its domestic customers by about 10 to 15 percent. This is indicative of the importance that NB places on continued electricity trade with both its neighbouring Canadian and U.S. utilities.
- Comparing the cost of NB's nuclear generation with Québec's hydro plants indicates limited opportunities for large long-term firm deals between the two provinces.
- Negotiating margins between NB and PEI are large. Utilities in both provinces concluded a three-year agreement starting in November, 1991 for the sale of 20 MW from the Point Lepreau nuclear plant.
- The long-run cost of the most economic unit in the Maritimes (i.e. Sheet Harbour) has been estimated at 66 mills/kW.h.
- To help reduce electricity costs in the Maritimes, the Maritime provinces may benefit from the joint planning and development of their generating and transmission facilities through the formation of a tight pool.
- In the mid to late 1970's the Maritime utilities undertook extensive studies on the feasibility of creating a Maritime Energy Corporation (MEC) with Point Lepreau No. 1 designated as a pool unit. MEC's mandate would have included both capacity planning on a regional basis and the coordination of systems operation as a single operating entity. However, for a number of reasons the MEC was never formed.
- Such a pool could have a combined installed capacity of 7000 MW by the year 2000. It would be only slightly smaller than that of Alberta in the same time period.

- The Maritime utilities are currently investigating if there are any significant further savings available to the region if they were to do their planning on the basis that provincial boundaries did not exist.
- Negotiating margins between Québec and PEI are even larger than those between New Brunswick and PEI. However, transmission access and the cost of wheeling Québec's power through NB to PEI could hamper such trade. From Québec's viewpoint any sales to PEI would be very small compared with their other out-of-province sales.
- Although the negotiating margins between Québec and NS are significant, the same problems of transmission access through NB would have to be resolved before any deals were realized.
- NB has over the years focused on the export market for increased trade opportunities. However, the negotiating margins between new nuclear units in NB and coal-fired generation in New England are not very large. This confirms the difficulty NB is having in its current negotiations with several New England utilities for the export sale of 400-600 MW of long-term firm power. The only overriding factor which favours such a deal is that while NB can still build new large-scale generating facilities, New England, for a host of regulatory and environmental reasons, may be unable to build large-scale coal-fired plants for in-service in the mid 1990's when supply deficits are expected to occur.
- Negotiating margins between NB and NE increase from 12 to 34 mills/kW.h if comparisons are made between nuclear generation in NB and combined cycle natural gas-fired generation in NE.
- Québec is decidedly more competitive than New Brunswick in the New England market as its negotiating margins are double those of New Brunswick. It is therefore not surprising that Québec was able to conclude an agreement with Central Maine Power (CEMP) for the long-term export sale of 1000 MW. However, the Maine Public Service Board subsequently did not approve the contract, and the deal was never finalized.

- It is understood that Québec and NE are continuing to negotiate a new contract. However, based on Québec's current supply situation it is unlikely that any new export deal with NE would commence before the early 2000's.
- Possibilities may also exist for a combined Québec/Maritime export deal with NE.
- Québec's generation is predominantly hydraulic and therefore subject to the vagaries of precipitation. In addition, the Québec system has historically not matched up to the reliability of other North American systems within NPCC, although significant expenditures have been allocated to improve this situation. It should be noted, however, that Québec's system characteristics (i.e. long radial lines connecting its hydraulic generation to load centres) have made it difficult in the past to abide by NPCC criteria. Generation in the Maritimes, on the other hand, is predominantly coal-fired or nuclear with secure fuel supplies. The fact that the Maritime utilities generally meet the reliability standards and criteria set by NPCC, coupled with New Brunswick's strategic position between Québec and New England, may offer opportunities for more reliable and higher-valued combined Québec-Maritime exports to New England.
- Although not explicitly included in Region No. 5, Newfoundland could gain access to the Maritime market if it could obtain transmission access through Québec. Under such a scenario, the results indicate that the negotiating margins between Newfoundland and the Maritime provinces are not too dissimilar from the margins between Newfoundland and New England as identified in Region No. 4. The reason for the similarity is based on the premise that in both New England and the Maritime provinces the preferred supply alternative is coal-fired generation with similar supply costs.

6.3 Assessment of Benefits from Regional Cooperation and Development Opportunities

Section 6.2 provided a qualitative review of the cooperation and development opportunities that may exist among utilities within the interconnected North American regions. Many types of opportunities exist, but it appears clear from this assessment that there are five major types that could contribute to increased inter-utility trade. These are:

- sharing of generation reserves among systems;
- firm seasonal diversity exchanges between Canadian winter peaking and the US summer peaking systems;
- firm summer exports by Canadian systems;
- benefits arising from new interconnections between systems; and
- long-term firm trade (i.e. the build or purchase option).

Based on the observations provided in Section 6.2, this section attempts to assess the potential net benefits that could be realized from the types of trade opportunities referred to above.

This assessment was made by using simple engineering economic models and simplified assumptions in order to calculate the magnitude and scope of the potential benefits from transactions between the interconnected utilities within each region. The results of these analyses should only be taken as providing a rough indication of the potential benefits that might exist through greater regional cooperation. It should also be noted that the potential opportunities and resulting benefits described in this section by no means cover the full range of opportunities that might be realized.

Opportunities through greater inter-utility cooperation and development, broken down into the five categories described above, are detailed below.

6.3.1 Sharing of Generation Reserves

Interconnections between systems allow utilities to share the generation reserves that must be installed to provide a reliable and secure supply of electricity to customers. The total amount of reserves that would have been required is thereby reduced, providing tangible economic benefits to both parties.

Most interconnected Canadian utilities have agreements which allow them to share generation reserves. As these types of benefits are now being realized and will continue to be realized in the future, it was considered unnecessary to deal further with these

matters here, except as noted in the section concerned with benefits arising from new interconnections.

6.3.2 Seasonal Diversity Exchanges and Summer Sales

Canadian utilities are winter peaking systems and consequently have surplus capacity during the summer months. U.S. utilities, on the other hand, are summer peaking systems with surplus capacity during the winter months. Potential opportunities thus exist for summer/winter seasonal diversity exchanges between Canada and the U.S. In those cases where Canadian utilities cannot be assured or do not plan to rely on return capacity and energy in the winter period, summer sales opportunities exist.

It should also be noted that long-term firm summer sales require the selling utility not only to have assured surplus summer capacity, but also assured annual energy above its own domestic needs and other firm commitments to support such transactions. In general, systems which are predominantly thermal-based and energy-rich have a greater opportunity to engage in these sales than do hydro-based systems. The energy capabilities of hydro systems are dependant on precipitation and therefore may be energy constrained. Firm summer sales are still possible but they tend to be negotiated on a year-to-year basis depending on the availability of surplus hydro energy.

The net benefits from seasonal diversity exchanges can be calculated as the difference between the generating facility capital deferments and the cost of the transmission facilities necessary to make exchanges.

The gross benefits from long-term summer sales were calculated as the savings from the displacement of the energy and the deferment of capacity on the purchaser's system. Total cost was comprised of the seller's production costs plus the cost of transmission facilities required for the trade.

6.3.3 New Interconnections

Significant potential benefits exist when new or additional interconnections between utilities are placed in service. These benefits include reductions in generating reserve margins, as well as opportunities for short-term economy energy trade and energy banking.

Additional interconnections provide opportunities for utilities to further reduce the total amount of reserve that would be required to provide reliable electric service. As noted above, such reductions provide tangible economic benefits to the interconnected parties.

Short-term economy energy trade allows interconnected utilities access to less-expensive generation than that currently available on their own systems. Economy energy from the supplying system is used to displace energy that could otherwise be produced by the receiving system, but at a higher incremental cost. This results in economic benefits to both parties.

Energy banking allows low-cost off-peak generation from a predominantly thermal system to be stored by an interconnected predominantly hydro system during the off-peak hours of the day. The energy is later returned to the thermal system during peak hour periods when the marginal cost of generation is high.

6.3.4 Long-Term Firm Trade

In order for utilities to meet their forecast increase in customer demands they have the choice of either building new generating plant or purchasing from others. The net benefits from long-term firm trade can be calculated as the difference between the purchaser's and seller's generation costs, less the cost of transmission facilities necessary to effect the transactions.

6.3.5 Summary of Estimated Benefits

Table 6.1 provides a summary, by region, of the potential cooperative arrangements that exist between interconnected Canadian systems as well as between Canadian and U.S. systems. Also shown are the net benefits that might be realized if these opportunities were exploited. Finally, those opportunities that have already been realized are shown in order to provide some indication of the relative magnitude that remains to be exploited.

The contract period for all future cooperative transactions was assumed to be 30 years, with the exception of the portion of Gull Island and Muskrat Falls power that would be used to defer hydro-electric generation in Québec, where a contract period of 60 years was used.

TABLE 6.1
Summary of the Potential Net Benefits by Regions
from Cooperation and Joint Developments
All values in \$ of 2000 using a real discount rate of 6%.

Region	Type of Trade	Systems	Characteristics	Amt. of Exchange MW	Potential Net Ben. \$ billions	Trade Already Realised
# 1 BC/Alt/ California	Sharing of Generation Reserves	BC-Alta	Intertie Cap. 600-800 MW			yes
	Seasonal Diversity Exchanges	BC/Alt with California	Winter Peaking Summer Peaking for 30 years	500	\$1.5	
	Summer Sales	BC/Alt to California	30 year 6 month/yr summer sale at 80% seasonal c.f.	1000	\$2.7	
	Long Term Firm Sales	BC/Alt to California	30 year sale at 80% c.f.	1000	\$2.8	
# 2 Sask/Man US Midwest	Seasonal Diversity Exchanges	Sask/Man. with US Midwest	Winter Peaking Summer Peaking for 30 years	850	\$5.5	500 MW between Man. & MAPP and 100 MW between Sask and Basin Electric
	Long Term Firm Sales	Manitoba to North States Power				Man. export of 500 MW to North. States Power from Limestone G.S.
# 3 MAN/ONT QUE/NY ECAR	Sharing of Generation Reserves	Ont-Que Ont-ECAR Ont-NY Que/NY	200 - 1450 MW 1000 - 2500 MW 3200 MW 1400 MW			Yes
	Seasonal Diversity Exchange	Ontario with ECAR	Winter peaking Summer peaking	500	\$3.2	
		Quebec with New York	Winter peaking Summer peaking	1400	\$10.5	800 MW between Que. and NYPA
	Summer Sales	Ont - ECAR	30 year 6 month/yr Sale at 80%	1000	\$2.7	
	Long Term Firm Sales	Manitoba to Ontario				Manitoba 1000 MW sale from Conawapa G.S. to Ontario
		Ontario to ECAR	30 Year Long Term Sale	1000	\$1.5 - 3.2	
		Quebec to NY	30 Year Long Term Sale	1000	\$2.2 - 4.0	Quebec has neg. a 500 MW export to Vermont.

TABLE 6.1 (con't)
Summary of the Potential Net Benefits by Regions
from Cooperation and Joint Developments
All values in \$ of 2000 using a real discount rate of 6%.

Region	Type of Trade	Systems	Characteristics	Amt. of Exchange MW	Potential Net Ben. \$ billions	Trade Already Realised
# 4 Ont/Que/ Nfld/NY/NE	New Interconnection	Ont - Que	Res. sharing Economy Trans Energy Banking	200 MW 3000 GWh/yr 450 GWh/yr	\$0.6	
	Exploitation of Gull Island & Muskrat Complex in Lab	Newfound.	To back off Isld thermal generation & defer Isld gen.	800 MW 150 MW (recall) 950 MW	\$4.5	
		Total				
		Quebec	To defer Hydro Gen. in Quebec	1000 - 2200 MW	\$1.5 - \$3.3	
		NB and NS	to defer coal gen. in NB and NS	0-750 MW	\$0 - \$2.1	
		N. England	To defer coal and/or Nat. Gas fired gen. in N. England	0 - 1200 MW	\$0 - \$7.2	
		TOTAL BENEFIT :				\$7.8 - \$13.2
	Long Term Firm Sales	Nfld to Quebec				Nfld sale of 5200MW from Churchill Falls G.S. to Quebec
# 5 Que/NB/PEI/ NS/NE	Sharing of Generation reserves	Que - NB NB - PEI NB - NS NB - NE	730 - 930 MW 40 - 140 MW 400 MW 30 - 1000 MW			Yes through the Maritime Power Pool.
	Seasonal Diversity Exchanges	NB NE	Winter peaking Summer Peaking for 30 years	150	\$1.1	
	Summer Sales	NB to NE	30 years sale at 80% seasonal c.f.	250	\$1.0	
	Long Term Firm Sales	NB - PEI	30 years sale up to 80% c.f.	50	\$0.4	NB sale to PEI include 50 MW and 20 MW from Lepreau #1
		NB - Que				NB sale of 400 MW G.T. to Quebec
		Combined NB/NS Sale to NE	Construction of Lepreau #2 and coal gen. in NS to defer Nat. gas gen. in NE	600 ~~600~~ 1200	\$2.3	NB has up to 230 MW of firm exports to NE from the Lepreau #1 nuclear unit.

From Table 6.1 the following observations are noted:

- Even if U.S. utilities in the Pacific Northwest and in California take full advantage of the seasonal diversity exchange and/or summer sales potential that exists between them, there remains significant scope for further winter/summer seasonal diversity (i.e. 500 MW) and summer sales (i.e. 1000 MW) between the combined B.C./Alberta systems and California. These potential net benefits have been calculated at \$1.5 and \$2.7 billion, respectively. Whether these transactions will ever be realized will depend upon securing transmission access through the BPA system.
- Opportunities also exist for major long-term firm sales to California. For example, a 1000 MW joint B.C./Alberta development would provide significant net benefits to all parties concerned. Net benefits from such a proposal have been estimated at \$2.8 billion.
- About 850 MW of potential winter/summer seasonal diversity exists between Saskatchewan/Manitoba and the utilities in the U.S. Midwest. Net benefits have been calculated at \$5.5 billion. It should be noted, however, that at present both Saskatchewan and Manitoba have seasonal diversity arrangements with U.S. utilities (100 MW for Saskatchewan and 300 MW for Manitoba). In addition Manitoba has entered into further diversity exchanges with Northern States Power and the United Power Association which will increase its total to 500 MW.
- The potential for seasonal diversity exchanges between Québec and New York has been estimated at 1400 MW with a corresponding net benefit of about \$10.5 billion. It should be noted that Québec and NYPA already have an 800 MW diversity agreement and thus a large portion of this potential has already been exploited.
- Ontario does not have a policy of encouraging exports of electricity, and in fact with respect to nuclear generation, imposed a moratorium in the fall of 1990 on the construction of new plants. This makes development of export-dedicated nuclear plants impractical at this time. Nevertheless this analysis appears to show that long-term firm nuclear power exports from Ontario to ECAR or New

York could provide major benefits to the parties involved. Net benefits from a 1000 MW export could range from \$1.5 to \$3.2 billion depending on whether those exports would defer U.S. coal or natural gas-fired generation.

- Québec does have a policy of encouraging electricity exports. Net benefits from a long-term sale of 1000 MW has been estimated to range from \$2.2 to \$4.0 billion. To date Québec has made a long-term firm contract of 500 MW to Vermont Joint Owners but its contract to supply 1000 MW to New York has been cancelled.
- Manitoba and Ontario have negotiated a 1000 MW long-term firm sales/purchase agreement which would require the construction of the Conawapa hydro plant in Manitoba to support the sale.
- The maximum potential seasonal diversity and summer sales potentials that appear to exist between Ontario and utilities in ECAR are 2500 MW and 5000 MW respectively. Ontario's generation at the margin is coal and due to the province's stringent acid gas emissions criteria, these opportunities may not be fully exploited. In addition, ECAR is made up of many interconnected utilities and the seasonal diversity opportunities may be difficult to realize. Furthermore, scheduled maintenance of large generating units during the summer period would also reduce the potential for such trade. Finally, even if transmission facilities were built to support these transactions, loop flows and other transmission bottlenecks might restrict such activities. As a result the expected seasonal diversity and summer sales potentials are estimated to be 500 MW and 1000 MW, respectively. The corresponding net benefits have been calculated to be \$3.2 billion and \$2.7 billion respectively. These types of transactions cannot occur simultaneously. Therefore, the benefits from them are not additive.
- A new 1000 MW HVDC interconnection between Québec and Ontario is estimated to provide net benefits of \$0.6 billion arising from potential reductions in generation reserve requirements, as well as from opportunities for economy energy trade and energy banking.
- Gull Island and Muskrat Falls appear to be among the lowest-cost potential generation developments in Canada. A fast-track exploitation of these facilities

would supply the Island of Newfoundland with 950 MW of base load capacity, including 150 MW of recall power from Churchill Falls, and would provide Québec and New England with 1000 MW and 1200 MW of long-term firm purchases, respectively. The overall net benefits from such a development scheme could reach \$13.2 billion.

- An alternative exploitation scenario for Gull Island and Muskrat Falls, whereby capacity which is surplus to Newfoundland's requirements is purchased by Québec, yields net benefits that are estimated at \$7.8 billion. A third scenario has Québec purchasing only 1450 MW, with the remaining 750 MW purchased by New Brunswick and Nova Scotia to defer coal generation. Under these assumptions, the net benefits are estimated at \$8.8 billion. Both these scenarios result in all the benefits remaining in Canada.
- Potential for seasonal diversity exchanges of 150 MW and summer sales of 250 MW appears to exist between New Brunswick and utilities in New England with corresponding net benefits for each in the range of \$1.0 billion. However, because New England's winter and summer peak loads are so close in magnitude, it is uncertain whether these benefits can be realized.
- Long-term firm sales of 50 MW by New Brunswick to Prince Edward Island could result in net benefits of \$0.4 billion.
- New England requires about 600 MW of new capacity each year to meet its forecast increase in electricity demand. A combined New Brunswick - Nova Scotia long-term firm export option to NE of about 1200 MW based on coal-fired generation could provide net benefits of approximately \$2.3 billion. However such deals may be difficult to realize because of the factors used by NE in their evaluation of projects. In particular, emission externalities make natural gas the fuel of choice and may override the benefits from the potential purchases from NB/NS. To date New Brunswick has negotiated up to 230 MW of firm exports from the Point Lepreau nuclear unit to utilities in New England.

Table 6.2 summarizes by type the additional long-term net benefits that appear to be available from enhanced inter-utility cooperation from the year 2000. The summary ignores the remaining benefits that could still be realized from seasonal diversity

TABLE 6.2
Summary by Type of Long-Term Net Benefits¹
from Enhanced Inter-utility Cooperation
 (All values in \$ of the year 2000 calculated using a real discount rate of 6%)

Type	Capacity MW	Net Benefit \$ billion
Seasonal Diversity Exchanges:		
- B.C./Alta - California	500	1.5
- Ontario - ECAR	500	3.2
- N.B. - New England	150	<u>1.1</u>
		<u>5.8²</u>
Summer Sales:		
- B.C./Alta to California	1000	2.7
- Ontario to ECAR	1000	2.7
- N.B. to New England	250	<u>1.0</u>
		<u>6.4²</u>
New Interconnections:		
- Ontario - Québec	-	<u>0.6</u>
Firm Sales:		
- B.C./Alta to California	1000	2.8
- Ontario to ECAR	1000	1.5 to 3.2
- Québec to New York	1000	2.2 to 4.0
- Devt. of Lower Churchill	2200	7.8 to 13.2
- Maritimes to New England	1200	<u>2.3</u>
		<u>16.6 to 25.5</u>
TOTAL LONG-TERM NET BENEFITS		<u>23.6 to 32.5</u>

Note: 1 The estimates presented here were made using simple engineering models and simplified assumptions. Therefore, they should be viewed as providing only a rough indication of the potential long-term benefits that could be achieved through enhanced inter-utility cooperation.

2 Seasonal diversity exchanges and summer sales are mutually exclusive and, therefore, the estimated net benefits from them are not additive.

exchanges between Manitoba and the U.S. Midwest, and between Québec and New York, on the basis that these benefits will likely be achieved through extensions to existing cooperative efforts. The long-term net benefits presented in the Table total between \$29 billion and \$38 billion. These should be regarded as providing only a rough estimate of the net benefits available from further inter-utility cooperation.

It should be noted that, with the exception of the lower estimate of benefits resulting from development of the Lower Churchill hydroelectric projects in Labrador and the relatively minor return from a new interconnection between Ontario and Québec, the benefits of further cooperation, as estimated here, are achievable through addition international rather than interprovincial trade.

6.4 Other Illustrations of Potential Benefits from Cooperation

6.4.1 Responses to Board Questionnaire

As detailed in Chapter 5, the information supplied by interested parties, particularly the electric utilities, demonstrates some of the existing and potential monetary and other benefits flowing from inter-utility cooperation. The potential benefits are clearly significant enough to justify further study and negotiation among the utilities involved.

6.4.2 B.C. Hydro/Alberta Coordination Study

In March 1989 a report on the above study was published. The study considered the following four options for increased coordination:

- Option 1 - Coordinated operation.
- Option 2 - Coordinated operation and construction, retaining the planned order of new projects on each system with maximum deferral according to combined system needs.
- Option 3 - Coordinated operation and construction with Alberta combustion turbines replaced by B.C. Hydro hydroelectric peaking capacity.

Option 4 - Coordinated operation and construction with coal-fired Alberta generation used to meet energy needs in both systems; and hydro peaking capacity from B.C. used to meet peaking needs in both systems.

Estimated savings ranged from \$600 million for Option 1 to \$1200 million for Option 4 in present worth 1988\$ for the period 1990 to 2010. These savings did not include transmission costs.

A subsequent assessment, including transmission costs, estimated median savings at \$400 million in present worth 1989\$ for the period 1990-2010.

6.4.3 Western Electric Utility Cooperation

In a report in May 1990 to the Western Premiers (of British Columbia, Alberta, Saskatchewan, and Manitoba) the Task Force on Western Electrical Utility Cooperation gave an overview of the potential benefits from utility coordination, including current benefits and those identified from previous studies. These include benefits from hydro/thermal synergy, reserve sharing, load diversity, and economic dispatch. They also include coordinated timing of new facilities and joint project development to meet the needs of the coordinated systems.

6.4.4 Maritime Energy Corporation

In a feasibility study published in July 1977, by the three Maritime electric utilities, the PEI Department of Industry and Commerce, and the federal Department of Energy, Mines and Resources, it was estimated that savings stemming from integrated expansion and operation of the Maritime electric utilities would be between \$100 and \$500 million representing some 2 percent to 10 percent of total costs over a 15-year study period.

At present the Maritime utilities are conducting a new investigation of potential saving resulting from joint utility planning.

6.5 Conclusions

This chapter has demonstrated that the potential benefits to be derived from increased inter-utility cooperation are significant enough to warrant continued efforts by Canada's electric utilities, and by the provincial and federal governments to assist in realizing these benefits. However, it should be recognized that the bulk of the benefits available from greater inter-utility cooperation will result from trade between Canada and the United States.

7. MEASURES TO ENHANCE COOPERATION

7. MEASURES TO ENHANCE COOPERATION

7.1 Introduction

This chapter begins by clarifying the authority of the provincial and federal governments under the Constitution Act with respect to the development and management of natural resources, and the generation, transmission and distribution of electricity. It then draws together the central conclusions and lessons learnt from the preceding chapters and suggests a set of principles that are necessary for inter-utility cooperation to function and grow. Finally, it outlines a range of policy options available to enhance inter-utility cooperation, as well as measures that the utilities and both levels of government might take to achieve this goal.

7.2 Federal/Provincial Authority

This section details the powers of the provinces and the federal government on matters relating to resource management and the generation, transmission and distribution of electricity.

7.2.1 Provincial Powers

Under the Constitution Act of 1867, legislative authority for electricity generation, transmission and distribution rests primarily with the provinces. Provincial ownership of most energy resources stems from Section 109 of the Act, which in turn is supplemented by Section 92A.(1)(c) giving provinces jurisdiction over the "development, conservation and management of sites and facilities in the province for the generation and production of electrical energy" and, hence, over electrical generating facilities. The provinces obtain jurisdiction over intra-provincial transmission networks pursuant to Section 92(10) of the Act. Under Section 92A, which was enacted in 1982, the provinces also have the authority to make laws regarding interprovincial sales of electricity, as long as such laws do not conflict with federal laws and do not permit discrimination in prices or supplies sold to different parts of Canada.

Because electricity service was commonly viewed as an essential prerequisite to economic development, the extension of electricity service and the development of new generation and transmission facilities formed important components of the economic and

social development policies of provincial governments. Given these objectives and the natural monopoly position of electric utilities, most provinces eventually decided to create public provincial utilities which were mandated to provide a secure supply of electric power to provincial residents at least cost. Today, all provinces, with the exceptions of Alberta and Prince Edward Island, are primarily served by provincially-owned electric utilities. However, Nova Scotia Power is currently undergoing privatization.

Provincial governments exercise control over the electric utility industry in two areas. The first area of provincial overview relates to rates charged to electricity consumers in the province. While some provincial utilities have the mandate to set prices, most provinces have established provincial boards which are responsible for reviewing and, in most cases, approving customer electricity rates. These boards are also generally responsible for reviewing any potential rate impacts that would occur as a result of long-term firm commitments to markets external to the province. The federal government has no involvement in provincial rate setting.

The second area of provincial overview relates to the development of the electric utility industry within the province to serve in-province loads and interprovincial and international commitments. The construction of new generating facilities and transmission grids, and associated environmental and right-of-way issues are subject to regulatory approval in all provinces although the degree of supervision varies.

7.2.1.1 Provincial Utility Regulation

The nature of provincial regulation with respect to these two areas is described briefly below.

Newfoundland

Newfoundland Light & Power Company (NLPC) and Newfoundland and Labrador Hydro (NLH) are regulated by the Newfoundland Board of Commissioners of Public Utilities. The Board fully regulates the rates and policies of NLPC, including the construction of new facilities. Since 1977, the Board has also had authority under the Electric Power Control Act to review NLH's rates for residential customers. The Board

makes recommendations to the Newfoundland Cabinet, which is the final authority for utility rates.

Cabinet is also the final authority with respect to NLH's capital expenditure program. Proposals by NLH for new facilities must receive Cabinet approval before construction can begin. NLPC must receive the approval of the province's Board of Commissioners of Public Utilities before proceeding with the construction of new facilities.

Prince Edward Island

Maritime Electric Company Limited is regulated by the Public Utilities Commission of Prince Edward Island under the provisions of the Electric Power and Telephone Act. The Commission has decision-making authority over electric utility rates in the province and screens all proposals for the construction of new generation and transmission facilities. If the Commission believes that a new facility may adversely affect the environment, a formal environmental assessment review process is initiated.

Nova Scotia

Since 1976, the Nova Scotia Board of Commissioners of Public Utilities, in accordance with the provincial Public Utilities Act, has had full decision-making power over the utility's rates and policies.

The Board's authority extends to the construction of new facilities, and utilities are required to apply directly to the Board when planning new generation or transmission facilities. As part of the review process, the Board holds public hearings, during which the utility presents its proposed project, costs and alternative plans. Members of the public may intervene directly during a hearing. The Board of Commissioners is the final authority on new facilities.

New Brunswick

As a Crown corporation, New Brunswick Power reports to the provincial government through its Chairman, who is a member of the Provincial Cabinet. The affairs of the Corporation are administered by an eleven-member Board of Directors including, ex officio, the President of the Corporation.

Changes in the charges, rates and tolls charged by New Brunswick Power must have the approval of the New Brunswick Board of Commissioners of Public Utilities under the Public Utilities Act. The Board has no jurisdiction to regulate the affairs of the corporation, to recommend or approve its borrowings, its construction, maintenance or re-construction of new or existing facilities, or its contracts for the sale to or purchase from interconnected electrical utilities outside the province.

Construction of new facilities must be preceded by an environmental impact assessment pursuant to the Clean Environment Act of New Brunswick.

Québec

In Québec, the National Assembly's committee on economics and employment reviews Hydro-Québec's long-term development plan, which includes any proposed rate changes. The committee then makes a recommendation to the Minister of Energy and Resources, who in turn makes a recommendation to Cabinet. Rate changes can therefore be implemented by Hydro-Québec only after they have been approved by Cabinet.

The construction of new facilities by Hydro-Québec can take place only after the utility has received a decree from the provincial government. Before an Order is issued, the Department of the Environment and the Department of Energy and Resources must approve plans for the new facility. Other departments and agencies are also consulted.

Ontario

Ontario Hydro is a provincially-owned corporation, which reports to the government through the Minister of Energy. The management of Ontario Hydro is under the direction and control of its Board of Directors. Proposed rate changes are referred to the Ontario Energy Board (OEB), through the Minister of Energy, for examination at public hearings. However, it is the Board of Ontario Hydro that is authorized to set the utility's rates, and it may accept or reject the recommendations of the OEB.

On matters concerning its generation expansion program and transmission facilities, Ontario Hydro is regulated by the provincial Joint Hearing Board. The Board is composed of members from the Environmental Assessment Board and the Ontario

Municipal Board. The Joint Hearing Board makes a recommendation to the provincial government, and final approval must be given through an Order in Council.

Manitoba

Under the Manitoba Crown Corporations Public Review and Accountability Act of 1988, Manitoba Hydro's proposed changes to domestic rates must be reviewed by the Manitoba Public Utilities Board, which holds a public review and makes a final decision on the proposal.

Under the 1988 Manitoba Environment Act, the provincial government must also approve major facility construction. Applications are made to the Minister of the Environment and a full environmental assessment is required.

Saskatchewan

Saskatchewan Power Corporation (SaskPower) is governed by a government-appointed Board of Directors that is responsible for the management and operation of the Crown utility. Proposals to increase rates or construct new generation or transmission facilities must be approved by the Board of Directors. The minister responsible for SaskPower is a member of the Board.

Alberta

TransAlta Utilities Corporation and Alberta Power Limited are regulated by the Alberta Energy Resources Conservation Board (ERCB) with respect to the development of generation and transmission facilities, coal mine developments and changes in service areas. Thermal generating stations are issued permits, which are subject to the Lieutenant Governor in Council approval, while hydro dam approvals require final authorization through the passage of a Bill in the legislature. TransAlta's and Alberta Power's rates are regulated by the Alberta Public Utilities Board, under the provisions of the Public Utilities Board Act of 1980.

As a municipally-owned utility, Edmonton Power is subject to the authority of Edmonton City Council. Its rates and financing are regulated by City Council, while the ERCB is responsible for the regulation of new generation and transmission facilities.

The three utilities participate in the cost-pooling program of the Electric Energy Marketing Agency (EEMA). The EEMA was established in 1982 by the provincial government to help equalize power rates throughout Alberta. Under EEMA legislation, the utilities' generation and transmission costs are regulated by the Public Utilities Board. The Board also approves the selling prices of electricity to EEMA, which then pools the utilities' costs and resells the power at average prices back to the utilities.

British Columbia

Changes in electricity rates in the Province of British Columbia require the approval of the British Columbia Utilities Commission (BCUC). Major generation and transmission projects require the approval of the provincial Cabinet. Upon receiving an application to construct a major facility, the government may refer the application to the BCUC for review and a recommended course of action. Projects that obtain Cabinet approval receive an Energy Project Certificate from the province.

Yukon

The Yukon Energy Corporation and the Yukon Electrical Company are regulated by the Yukon Utility Board, under the Public Utilities Act of 1986. Under this Act, the Corporation and Company must file applications for rate changes or facility construction with the Board, which reviews the applications and makes a decision.

Northwest Territories

The Northwest Territories Power Corporation and Northland Utilities Enterprises Limited are regulated by the Northwest Utilities Act of 1989. Under the Act, they must file an application with the N.W.T. Public Utilities Board in order to receive authority for rate changes or facility development. Upon receiving an application, the Board holds a public hearing and then reaches a decision, which is final.

7.2.1.2 Provincial Non-utility Generation Regulation

Concurrent with the establishment of provincial and private utilities in the various provinces to supply the present and future electricity needs of those provinces there has

also been a growth in non-utility generation. This growth occurred mainly in resource-based industries because of their particular requirements, unique franchises or rights obtained from the provinces. Through such instruments they have been able to build facilities to serve their electric power needs more economically than through purchases from electric utilities.

Hydro plants owned and operated by aluminum producers in Québec and British Columbia comprise by far the largest component of non-utility generation, followed by the forest products industry, where a significant portion of electricity production is based on consuming wood-waste and other by-products from paper-making processes. Many of these industries, as well as those in the mining/metals group, produce electricity to supply not only their own loads but also those of nearby isolated residential communities. This phenomenon has indeed led some industrial firms to separate the electricity production arms of their businesses and to create small utilities. Examples include the MacLaren Power Co. and West Kootenay Power.

Over the last decade there has been a renewed interest in non-utility generators (NUGs) playing a more important role in meeting future provincial electricity demands. In fact, during this period there has been a significant change in perception among private entrepreneurs, provincial governments and utilities that substantial benefits can be derived from smaller, less capital-intensive, diversified projects. Much of the current impetus for non-utility generation comes from the belief that private enterprise may be better-suited to develop and manage small-scale projects than are the large utilities.

Most provincial governments have now established policies and regulations to facilitate non-utility development. Many of these policies are directed not only to promote greater non-utility participation but also to encourage industries to utilize their byproducts or readily available resources to produce electricity when this is economically feasible.

7.2.1.3 Conclusions

It is clear from Section 7.2.1 that the governments of the provinces and territories exercise regulatory and resource management control over their respective electric utilities. In addition, many provinces have initiated policies to promote non-utility generation in recognition of the important role that exists for private investors to supply portions of provinces' electricity demands.

The success or failure of inter-utility cooperation to a very large extent will thus depend upon the provincial governments' policies, directives and actions to encourage and promote such cooperation. Since most Canadian utilities are interconnected both internationally and interprovincially, provincial interest in electric power system development extends beyond provincial and national boundaries, and thus, overlaps areas of federal jurisdiction.

7.2.2 Federal Powers

Under the Constitution Act, federal authority regarding electricity is restricted to nuclear energy, and international and interprovincial trade. Federal control of nuclear energy derives from Sections 91(29) and 91(10) of the Act, which permit federal regulation of matters that are declared by Parliament to be for the general advantage of Canada. Federal responsibility for electricity trade stems primarily from Section 91(2) of the Act which gives the federal government broad authority over trade and commerce, and Section 91(10)(a) which confers jurisdiction over extra-provincial works and undertakings.

7.2.2.1 Federal Legislation

Specific legislation regarding electricity enacted by Parliament is briefly described below.

Atomic Energy Control Act

Immediately after World War II, Canada began to study the question of how to encourage the use of nuclear energy for peaceful purposes while at the same time preventing its use for weapons. In 1946, Parliament passed the Atomic Energy Control Act with these objectives in mind.

The Act gives the federal government control over the development, application and use of nuclear energy, and established the Atomic Energy Control Board (AECB). The five-member Board administers and enforces the Act, from which it derives its authority to regulate the health, safety, security and environmental aspects of nuclear energy. The

AECB reports to Parliament through a designated Minister, currently the Minister of Energy, Mines and Resources.

The Board's primary function is to license Canadian nuclear facilities and activities dealing with prescribed substances and equipment. Nuclear facilities include power and research reactors, uranium mines and refineries, fuel fabrication plants, heavy water plants, waste management facilities and particle accelerators. Prescribed substances include uranium, thorium, heavy water and radioisotopes. Activities relating to such substances which may be licensed include production, processing, sale, use, import and export. Before issuing a licence, the AECB ensures that the appropriate health, safety and security standards are met. The AECB's control also extends to international security of nuclear materials and technology. Through the licensing process, it ensures that nuclear equipment and supplies are exported only in accordance with Canada's obligations under the Treaty on the Non-Proliferation of Nuclear Weapons.

National Energy Board Act

The National Energy Board (NEB) is a federal tribunal, created in 1959 by an Act of Parliament. The Board's powers and duties are derived from the National Energy Board Act. The NEB was created largely in response to concerns arising from increased interprovincial trade in gas and increased energy exports from Canada. The primary concerns of the government of the day, with respect to exports, appear to have been that quantities of exported energy be surplus to Canadian needs and that energy not be exported at prices lower than those charged to Canadians. Further, the government recognized the difficulties inherent in ensuring that these principles be observed in practice and charged the NEB with the responsibility of fulfilling the intent of the Act as determined by the Board itself.

The Board's jurisdiction over electricity matters is limited to the authorization of electricity exports and of international and designated interprovincial power lines. The Board has no jurisdiction over imports of electricity.

On September 6, 1988, a new policy concerning the regulation of electricity exports and international power lines was announced. Legislation amending the NEB Act to give effect to this policy (Bill - 23) was proclaimed on June 1, 1990.

Under the amended Act, electricity exports and international power lines will normally be authorized by issuance of a permit, without a public hearing, unless the Governor in Council, upon the recommendation of the Board, designates a proposed export or an international power line for licensing or certifying procedures. In determining whether to make a recommendation to the Governor in Council, the Board shall seek to avoid the duplication of measures taken by the applicant and the government of the province from which electricity is to be exported or through which a line is to pass, and shall have regard to all considerations that appear to it to be relevant. In the case of a proposed export, as described in Subsection 119.06 (2) (c) of the Act, those considerations shall include:

- (a) the effect of the export on provinces outside of the sponsoring province;
- (b) the impact of the export on the environment;
- (c) whether Canadians interested in making purchases to satisfy their own domestic requirements have been afforded fair market access to the electricity proposed for export; and
- (d) such other considerations as may be specified in the regulations.

Similarly, in the case of a proposed international power line, those considerations shall include:

- (a) the effect of the international power line on provinces outside of the sponsoring province.
- (b) the impact of the construction or operation of the international power line on the environment; and
- (c) such other considerations as may be specified in the regulations.

The maximum term of any licence or permit to export electricity is 30 years from a date to be fixed in the respective authorization.

Finally, under the amended Act, detailed routing and land acquisition in respect of international power lines will be carried out under provincial laws unless an applicant elects to have federal laws apply. In this case, the detailed routing and land acquisition procedures under the National Energy Board Act will apply.

7.2.2.2 Federal Policies

Hand in hand with the above-noted legislation, the federal government has, for national interest reasons, established over the years policies to encourage development in the electricity supply industry, and this continues today. Among the major federal policy initiatives are the following:

The 1963 Statement of the National Power Policy

In 1962, at the request of the government, the NEB carried out a number of studies on the development of hydro-electric power in Canada. In October 1963, the Minister of Trade and Commerce released a Statement of National Power Policy. This statement contained two essential concepts:

"First, encouraging development of large low-cost power sources and the distribution of the benefits thereof as widely as possible through interconnections between power systems within Canada; second, encouraging power exports and interconnections between Canadian and United States power systems where such induce early development of Canadian power resources."

The Statement went on to say that:

"The Government also believes that it would be in the national interest, in suitable cases, to license the export of large blocks of firm power to United States utilities to permit the development of large scale remote hydro or other power projects which would not be viable unless supported by the export for long periods of a significant proportion of the power generated ... The provisions of the National Energy Board Act would, of course, apply to any case of this nature, as to any export of power"

Nuclear Power Policy

To promote the peaceful use of atomic power the federal government provides annual funding to the Atomic Energy of Canada Ltd. (AECL), a federal crown corporation, for research and development (R&D). Recently a five-year funding agreement on R&D was concluded between the federal government and the provinces of Ontario, Québec and New Brunswick, provinces that have installed nuclear generation on their systems. The five-year agreement, in contrast to the previous annual funding arrangement, allows AECL to better manage its long-term R&D activities.

The 1974 CANDU Policy

To encourage the development of the Canadian nuclear industry it has been the federal government's practice to provide federal loans at government rates to those major provincial utilities who plan to install CANDU nuclear power generation on their systems. This practice was made official government policy in 1974. Under this policy, federal loans are provided to the province for up to 50 percent of the estimated capital cost of the first unit installed in the province. To date only Ontario, Québec and New Brunswick have exercised this option.

1974 Inter-regional Transmission Line Policy

The federal government has not, in general, exercised jurisdiction over interprovincial electricity trade except to include a special provision in the NEB Act which allows the Governor in Council to designate an interprovincial power line that is to be constructed and operated as an interprovincial powerline coming under the NEB Act (see Section 58(4) of the NEB Act).

Nevertheless, the federal government has, and continues to maintain, an interest and involvement in those activities which would increase economic efficiency and benefit electricity trade from both national and regional perspectives. The 1974 Interregional Transmission Line Policy is an example of just such a federal initiative. Under this policy the federal government would:

- provide funding for inter-regional transmission studies; and

- provide federal loans for up to 50 percent of the estimated capital cost of projects approved.

The submarine cable between New Brunswick and Prince Edward Island; the strengthening of the New Brunswick and Nova Scotia interties; and expansion of Manitoba's Nelson River HVDC transmission system are just some examples of the successful applications of this policy.

1988 Canadian Electricity Policy

As a result of the 1988 Canadian Energy Policy, amendments were made to the NEB Act in respect to authorizations for electricity exports and for the construction and operations of international power lines. The thrust of the policy was to reduce the regulatory burden and avoid the duplication of efforts between federal and provincial levels of government. In addition, substantive changes were made in respect to the Board's mandate. For example, no longer would the Board need to be satisfied with the surplus nature or the price of electricity exports. These matters would be left to oversight by provincial governments. The Board on the other hand, would concentrate on any extra-provincial impacts caused by the proposals, such as the impacts on the reliability of interconnected Canadian utilities, as well as whether Canadians were provided fair market access (FMA) to the electricity proposed for export. In addition, the policy makes sure that the NEB will examine proposals in the light of issues that will be important in the 1990s and beyond, such as the environmental impacts of such proposals.

7.2.2.3 Conclusions

The federal government's powers under the Constitution Act in respect to electric facilities are generally limited to those which are federal works and undertakings (i.e. principally international and designated interprovincial transmission lines). Through such powers the federal government has, over the years, initiated consistent policies to encourage greater inter-utility trade in electricity. To the extent appropriate, federal funding has been made available to assist in regional transmission interconnections which would improve economic efficiency and increase trade. This current review continues these federal initiatives and is a further indication of the federal government's resolve and commitment to open markets and reduce barriers to interprovincial trade.

7.3 Recapitulation of Findings

The principal findings of this review, as they relate to encouraging greater cooperation among utilities in systems planning and development, are discussed below in the following sections.

7.3.1 Historical Perspective

Past approaches to national, regional and bilateral electricity planning among Canadian electric utilities were examined and the following findings are noted.

National Power Grid

Despite the very considerable efforts of both the provinces and the federal government in the decades of the 1960s and 1970s, nothing even approximating a national power grid has ever come about. Four possible reasons for this were identified, but these are not necessarily exhaustive:

- (i) the estimated economic benefits from such a scheme were never sufficient to outweigh the financial risks involved;
- (ii) the autarchical perspective of provincial utilities;
- (iii) governments have been unwilling to establish an institution adequate to the task;
and
- (iv) the constitutional arrangements under which Canada is governed militate against the formation of a national power grid.

Barring these procedural and jurisdictional problems, other issues would have to be resolved in order for a national grid to be realized. These issues include the proposed sharing of costs and benefits, coordination of international trade, the type and location of new generating facilities, etc. A national electricity agency would have to settle all of these issues before a national grid could become a reality.

The historical evidence points to a single conclusion: a national grid - defined as an entity somehow separate from and transcending the several provincial grids - has not been an idea that has borne much fruit. In the two cases on record, governments rejected a national scheme in favour of expanding regional cooperation.

Regional Planning

From a review of the attempts to establish the Western grid, the Eastern grid and the Maritime grid the following findings are noted. In each instance the failure to establish these regional entities resulted from a lack of consensus on the total benefits to be derived, as well as a lack of political agreement between the federal and provincial governments.

In fact, for regional cooperation initiatives to be successful, political consensus is just as essential as the appeal of economic benefits and the support of the industry. Failure was inevitable when the negotiators failed to ensure that the provincial governments were informed and supportive of what they were doing.

This review suggests that the political dimension of regional cooperation initiatives need to be addressed at the same time as the technical, economic and financial issues. There must be a belief on the part of each participating province that the reduction in power costs resulting from increased cooperation will outweigh any decrease in its direct control over the planning of its electric power system.

Bilateral Arrangements

From a review of some eight bilateral initiatives, ranging from strengthening the interconnection between Nova Scotia and New Brunswick to those between Québec and Newfoundland to develop the hydro-electric sites on the Lower Churchill River, the following observations can be noted.

Utilities in all regions of the country are, in general, willing to participate in profitable interprovincial cooperative projects. However, when such arrangements require the provision of wheeling services to other parties, agreements have been difficult to achieve. Bilateral initiatives have succeeded where the provinces saw clear benefits which

outweighed the risks of participation. Of equal importance is the requirement that the provinces feel that the benefits of a joint project are shared equitably over its life; this is an essential component for a continued climate of cooperation. The success of bilateral initiatives has some lessons for those who wish to promote further interprovincial activities. Perhaps bilateral initiatives have succeeded where national and regional initiatives have not because the bilateral initiatives involved a narrower range of activities and offered a clearly-defined method of sharing risks and benefits. It is also of note that no bilateral initiative has involved the creation of a decision-making institution other than the provinces and utilities themselves. One likely reason for the willingness of provinces to enter into bilateral initiatives is that these do not involve a loss of control over the planning process. The challenge for those who design measures to increase interprovincial utility activities will be to create mechanisms that are effective at realizing economic gains, without losing the trust of the provinces and utilities.

7.3.2 Existing Inter-utility Cooperation

From an analysis of the responses to the Board questionnaire on current inter-utility cooperation, the following findings are noted:

There already exists in Canada a considerable degree of inter-utility cooperation, from which significant benefits are derived. Canada's electric utilities are also planning a significant amount of future inter-utility cooperation.

Such cooperation generally includes exchanges of economy energy, non-economy capacity and energy, reserve sharing, maintenance scheduling, emergency support, and limited coordinated operation. Typically, these activities are carried out under interconnection agreements negotiated on a bilateral basis. There is a very limited degree of integrated generation and transmission expansion planning.

Perhaps the highest current degree of cooperation exists in Alberta under the auspices of the Alberta Interconnected Power System Pool, described as a "tight" pool. This is, of course, an intraprovincial agreement and, as such, does not involve interprovincial problems.

Wheeling is limited and is generally restricted to cases where the sender and receiver are the same entity, or where power is sold by the generating utility to the wheeling utility, wheeled, and then sold to the utility whose customers will use it.

Generally, utilities are in favour of developing future initiatives by direct negotiation among themselves and a number feel that they should develop policies on wheeling similar to those established by BC Hydro/POWEREX.

In respect to the involvement by both levels of government in inter-utility cooperation, most utilities feel that governments' role should be that of providing leadership, developing policies, and providing clear, streamlined, stable, and coordinated regulation.

7.3.3 Role of Independent Power Producers

Concerning the possible role of independent power producers (IPPs) in facilitating interprovincial cooperation, the following comments by utilities have been noted.

The purchase of power from an IPP is generally not a factor in interprovincial cooperation unless the IPP in one province wishes to sell to a party in another province, necessitating wheeling arrangements by intervening utilities. Thus, IPPs may require interprovincial cooperation beyond existing levels if they arrange to sell to markets outside their own province.

Utilities, in general, would rather do business with major provincial utilities than purchase electricity from an IPP located outside the province because of a host of technical, financial and legal problems and uncertainties that such arrangements might entail. For example, any interconnection of an IPP's generation must be done in such a way that it will not have negative impacts on the system to which it is connected or on any systems which are in turn interconnected. Thus, IPPs would have to provide credible assurances of reliability and continuity of supply and would be responsible for obtaining all regulatory approvals.

To overcome these concerns, uniform provincial policies with respect to IPPs would be desirable. Governments could help facilitate wheeling arrangements by assisting utilities (e.g. by timely reviews, risk sharing) to overcome concerns they have about wheeling, including cost, reliability, lead time and priority issues.

One utility suggested that IPPs may also play a role in international electricity trade by increasing the export capabilities of the province through building new production facilities when the provincial utility is unable to do so. On the other hand, if the utility has surplus generation, increased export competition may reduce utility revenues and harm provincial customers.

Other utilities stated that IPPs would result in greater competition, with the potential for lower power costs. It was also recognized that other factors such as taxes, which are not always paid by utilities, create artificial differences which can distort economic comparisons and lead to a sub-optimal overall result. Over the long term, open markets created by wheeling within and among Canadian provinces, and between Canada and the U.S. would provide greater opportunities for IPPs to participate. This situation would have the potential for significant benefits, including improved reliability; varied sizes, locations and sources of generation; smoothing of peaks across time zones; and good matching of specific generation and loads.

7.4 Opportunities for Further Cooperation

The principal findings of the Board staff analysis in respect to quantifying the benefits and opportunities for inter-utility cooperation are as follows:

Geographic Considerations

Most Canadian electric utilities are interconnected both interprovincially and internationally. Therefore, Canadian regional cooperation and development opportunities must take into account the potential for international as well as interprovincial trade in electricity.

Because of the large geographic size of Canada and the United States, and the resulting technical and economic limitations, it is not possible for all provincial and state utilities to trade with each other. As a result, trade patterns follow certain natural geographic regions. Five such regions were identified and the potential for both interprovincial and international trade opportunities among Canadian utilities, and between Canadian and U.S. utilities, were assessed. The regions are:

- Region #1: BC/Alberta/U.S. Pacific Northwest/California;
- Region #2: Saskatchewan/Manitoba/U.S. Mid West;
- Region #3: Manitoba/Ontario/Québec/New York/ECAR;
- Region #4: Ontario/Québec/Newfoundland/New York/New England; and
- Region #5: Newfoundland/Québec/New Brunswick/PEI/
Nova Scotia/New England.

General Supply Cost Comparisons

Supply cost comparisons, using a levelized unit energy cost method, between utilities within regions indicate that, in many instances, the potential margins for negotiating power sales between utilities appear to be significant.

In many cases, the potential negotiating margins for international trade appear to be greater than those for interprovincial trade.

Potential Benefits From Specific Development Schemes

Many types of inter-utility development opportunities exist, but it appears clear from this assessment that the five major types are:

- sharing of generation reserves between system;
- firm seasonal diversity exchanges between Canadian winter peaking and U.S. summer peaking systems;
- firm summer exports by Canadian systems;
- benefits arising from new interconnections between systems; and
- long-term firm sales (i.e. the build or purchase option).

This review has indicated that, although significant opportunities appear to exist for enhanced electricity trade between Canadian provinces, even greater potential benefits would be available from increased trade between Canada and the United States. However, in order to maximize the benefits from international trade it might be necessary for Canadian utilities to form partnerships. Such cooperation within Canada has the potential to increase the quantity and quality of the electricity exports, thus increasing their value. Also, in order to realize the benefits identified, utilities, with the support of the provinces and states, might have to cooperate more fully in the planning of their systems on a regional basis and to provide transmission access and wheeling services.

7.5 Observations on Enhanced Cooperation

Electric utilities in Canada, like those in the United States, have the responsibility for providing reliable, environmentally-acceptable, low-cost electricity to customers within their service territories. For the large provincial Crown corporations, this usually includes the responsibility to serve most of the electricity needs of the province. They have therefore designed their power systems specifically to serve those provincial requirements. Furthermore, many Canadian and U.S. utilities are interconnected for the primary purpose of benefitting their customers through improved reliability and economy. This has required utilities to cooperate in systems operations and planning (particularly in intertie planning). This review points out that further improvements in inter-utility trade are possible through continued and increased cooperation in these areas.

Arising from this review several factors have been identified regarding greater inter-utility cooperation.

These are:

Geographical Location

The situation can arise whereby a utility, which is strategically located geographically by virtue of its having interconnections with several neighbouring utilities that are not themselves directly interconnected, has the opportunity to control or restrict electricity trade among its neighbours. In order to realize the benefits that would be available from enhanced inter-utility cooperation, it is important that the first utility does not attempt to

exercise this potential control but, instead, participates with neighbouring utilities in regional planning, development, and operations on a sound technical, environmental, economic and financial basis.

Trade-off between Increased Benefits and Reduced Provincial Control

Under the Constitution Act, the provinces have legislative authority over the development of electricity generation, transmission and distribution facilities, as well as the pricing of electricity, within their own borders. Also, most major electric utilities in Canada are provincially-owned corporations.

The general mandate of the utilities is to provide a reliable, environmentally-acceptable supply of electric power to their customers as least cost. However, there has been a tendency for the provinces, through their direct control over the utilities, to use the utilities as vehicles to help promote socio-economic and regional development programs and policies.

An increased level of cooperation among utilities on a regional basis can only be achieved if the provinces perceive that the economic benefits arising from such cooperation are large enough to compensate for some reduction in their control over the development and operation of electric power facilities within provincial boundaries.

Cooperation Could Involve Long Term Equity and Reciprocity

Inter-utility cooperation rests on the principle that the benefits that might accrue from regional developments must be shared equitably to ensure that in the long run all participants are better off. This requires reciprocity and a flexible attitude among the participants. For example, it may require a common understanding or commitment to stagger new generation between utilities in neighbouring provinces to ensure that all share in the economic benefits that arise from such developments.

Provincial/Federal Policies Could Focus on Eliminating Barriers to Electricity Trade

Provincial policies to encourage inter-utility cooperation could focus on the following measures:

- (i) Recognition that the electricity supply industry comprises large utilities, both public and private, as well as small private utilities and independent producers. This situation requires policies which will enable these enterprises to participate on an equitable basis.
- (ii) Joint regional developments require long-term commitments. It is therefore critical that provincial policies be stable, clear and long term in nature.
- (iii) Policies could be established to eliminate barriers to more IPP development and also allow for out-of-province IPP purchases from Canada or the U.S..
- (iv) Policies that would allow one province to invest in another province so as to participate in joint transmission and generation projects.

Specific federal actions might include:

- (i) Continue to strengthen existing policies to encourage increased trade.
- (ii) Policies to ensure that IPPs and utilities that are not directly connected to U.S. markets are provided with the ability to compete in the electricity export trade on an equitable commercial footing with utilities that do have direct transmission interconnection with the U.S.
- (iii) Recognize that significant U.S./Canada trade in electricity already exists. Any policies or regulations that might be established concerning interprovincial trade should not deter or detract from such international trade.

Inter-utility Cooperation Based on Least Cost Planning

The fundamental principle on which inter-utility cooperation should be based is that of supplying electricity service to customers at least cost. This principle corresponds with the general mandate of the utilities, and leads to economic efficiency. All other approaches are likely to be sub-optimal.

Cooperation Requires Consideration of Demand Side Management and Independent Power Producers

While it is true that the principal focus of inter-utility cooperation in system planning relates to regional transmission and generation developments, it is clear that opportunities for increased demand side management (DSM), as well as alternative supplies from independent power producers (IPPs) should be factored into the equation to ensure minimum long-run cost of electricity to consumers. To that end, utilities should exchange information and experience on their DSM programs in order to maximize the benefits as well as to avoid possible pitfalls. IPPs should be made part of the planning process by being provided with the appropriate incentives and policies that will encourage their vigorous participation.

Trade-off between Economic Efficiency and Reliability

The electric utility industry is perhaps unique among all other industries because system interconnections, although providing significant benefits, also force utilities to become strongly dependent on each other.

Interconnected system networks operate continuously in a state of unequal equilibrium. Any fault or failure of major equipment could cause the entire system to collapse in a matter of seconds. For these reasons, interconnected utilities in North America have voluntarily joined together to establish the North American Electric Reliability Council (NERC) to ensure and safeguard reliability of supply. Great strides have been made through cooperation among interconnected utilities in the form of providing assistance and support to each other in cases of emergency. Over the years, system planning criteria and operating codes have been developed with electricity reliability in mind. Through this inter-utility cooperation, the dependability and reliability of electricity service in North America has become unsurpassed. It is therefore imperative that increased trade should only occur within those prescribed reliability constraints to ensure that interconnected system reliability is not compromised.

Planning Requires Common Objectives

For regional planning to succeed there should be a recognition of the investments each participant is willing to make, and benefits that accrue should be commensurate with the risks taken. There should also be a recognition that there are benefits that can be quantified and those that cannot. All participants (i.e. provinces/utilities) should strive at the beginning of the review process to seek common ground on these matters. Once a "common reference" has been agreed upon, commitments to these principles must be obtained if success is to be assured.

Full Disclosure of Information is Critical

Systems planning on a regional basis requires full disclosure of information by all participants and a critical review of such information to reach accord and consensus. An important principle in systems planning must be the fostering of trust among participants to ensure that negotiations take place in good faith.

Systems Planning is a Continuous Long Term Process

Experience appears to confirm that when projects assessed by ad hoc committees are completed, any information gained from these assessments tends to become quickly lost and outdated. Therefore, successful inter-utility cooperation in systems planning might require the establishment of entities whose objectives are to continually monitor, assess and update regional development opportunities based on current information, facts, policies, etc.

Inter-utility Systems Planning Founded on Existing Institutions

To the extent possible it might be desirable for inter-utility systems planning to be founded on existing institutions and structures. As previously noted, most Canadian and U.S. utilities are members of one of the nine regional reliability councils under the NERC. More specifically, most Canadian utilities are members of one of three regional councils; namely the Western Systems Coordinating Council, Mid America Power Pool, and the Northeast Power Coordinating Council. Inter-utility cooperation on reliability concerns that now exist among the NERC member utilities could be used to build upon

organizations that encourage increased inter-utility cooperation on "economic" matters within those regions.

7.6 Options Available to Enhance Cooperation

A number of feasible options have been developed to encourage greater cooperation both among Canadian utilities and between utilities in Canada and the U.S. The options were established within the context of the factors outlined in the previous section and have been ranked in order of their complexity. They are by no means exhaustive but do provide a reasonable range of options for consideration.

7.6.1 OPTION 1: Continue Voluntary Cooperation

This review has demonstrated that Canadian utilities currently cooperate and trade both interprovincially and internationally. Under this option, the utilities would continue to enter into voluntary negotiations, usually on a utility-to-utility basis, to increase trade as they see opportunities arise. The agreements reached between the utilities would be made under existing provincial and federal regulations and policies. The federal government would participate in the study and implementation of future interprovincial and international projects within the context of current federal policies.

7.6.2 OPTION 2: Voluntary Cooperation with Federal Monitoring

Under this option, the utilities and provinces would continue to act as they do now but the federal government would undertake to monitor progress on cooperation on a regular basis. This could take the form of updates to parts of this review, with particular focus on the improvements in cooperation that had taken place, as well as on areas where there had been no progress. These reports would be public documents and would be available for use by both levels of government, utilities, and other stakeholders and interested parties in deciding on future courses of action.

7.6.3 OPTION 3: Establish Voluntary Regional Planning Entities

Under this option, Canadian utilities, together with their neighbours in the U.S. would establish, on a voluntary basis, regional planning entities whose main objective would be to identify opportunities for wider cooperation among them. The scope of such entities

could vary widely but, ultimately, they could engage in least-cost integrated resource planning on a regional basis and fully coordinated systems operation in a tight pool. These entities would provide a focus on "economic" improvements related to planning, development and operations of interconnected systems, in a similar way that the NERC regional councils now afford on "reliability" matters. They might also focus on "environmental" improvements that could be achieved by regional cooperation.

7.6.3.1 Scope of Entities

The scope for such entities could vary from very limited to wide ranging. In this regard it might be desirable to limit their scope initially but provide for the eventuality of widening the scope as experience and success warrant and dictate.

The following scopes, in increasing order of complexity, are suggested:

Information Exchange Only

Regional entities would provide focus for the interchange of information related to projections of supply and demand, supply costs, economic parameters used, etc. This would provide participants with information about other utilities' plans which in turn might influence their own planning decisions.

Transmissions Planning as a Result of System Operations

Economic and reliability benefits from inter-utility trade, in particular through operations and coordination of the interconnected systems, are currently being realized. However, system operation benefits might be improved through the elimination of transmission bottlenecks. The regional entity would therefore not only provide a forum for information exchange but would also focus on areas within the region where additional transmission lines would be required to remove any interprovincial or international transmission bottlenecks that hamper increased trade.

Bulk Regional Transmission Planning

The ability to improve or enhance inter-utility trade will depend, in large measure, upon the strength of bulk regional transmission networks. In addition to the activities described

above, the regional planning entity would also focus on long-term regional transmission planning to ensure that the networks are developed to serve the long-term regional system requirements.

Bulk Regional Transmission and Generation Planning and Operation

Finally, the highest level of regional integration is possible only when bulk regional transmission and generation planning and operations are undertaken similar to what now exists in a number of U.S. power pools and in the Alberta Interconnected System. Such regional integration results in the maximum level of interprovincial and international trade, and cooperation among utilities.

7.6.3.2 Responsibilities of Entities

Within the various scopes discussed, the basic responsibilities of the regional planning entities would be to:

- provide an avenue for information exchange among regional members;
- carry out regional investigations to promote trade including transmission access and wheeling;
- establish procedures to promote and ensure inter-utility cooperation;
and
- assist in resolving disputes that arise among members as they relate to electricity trade.

7.6.3.3 Membership of Entities

Membership would include all utilities within the region, as well as IPPs. Both levels of governments could be given observer status.

7.6.4 OPTION 4: Establish Regional Planning Entities with Mandated Federal Power

This is similar to Option 3, except that the federal government would exercise those powers that might exist to resolve disputes in matters involving international trade, and both international and interprovincial wheeling.

7.7 Involvement by Participants in the Regional Entities

It is clear from this review that increased regional cooperation requires the direct involvement of all participants, particularly the utilities, and the provincial and federal governments. The possible extent of such involvement is described below.

7.7.1 Utility Involvement

Utilities might provide assistance in the following areas:

- provide the major share of personnel, funds and infrastructure to establish and operate the regional planning entities;
- carry out all the necessary regional feasibility studies, and exchange information as widely and openly as possible;
- quantify the impacts on utilities of deviations from the preferred regional development plans;
- develop procedures to ensure that all members participate on an equitable basis. This would require agreement on the technical and economic parameters to be used, and consensus that policies on regional developments and wheeling would be based on reciprocity and equity;
- be prepared to invest in cost-effective projects in other provinces; and
- establish procedures for resolving disputes among members.

7.7.2 Provincial Involvement

Provincial governments might provide assistance in the following areas:

- assist in funding the establishment and operation of the entities;
- participate to the maximum extent possible in all phases of any regional development studies;
- set clear policies which would allow greater regional development to take place, including interprovincial wheeling. Such policies should reject the premise that geography alone can be used as a barrier to electricity trade, and should not be unduly biased by provincial preferences;
- develop policies that would allow private utilities to participate with provincial Crown corporations on an equitable basis. They should also allow IPPs to participate in regional supply opportunities to the extent possible; and
- participate, as appropriate, in any arbitration procedures to resolve disputes among participants.

7.7.3 Federal Involvement

To the extent appropriate the Federal Government might provide assistance in the following areas:

- coordinate the activities of the various regional entities to provide comprehensive national updates on the status of the electric power industry in Canada. This information could be used by the federal and provincial governments, utilities and other interested parties to monitor progress and highlight problem areas;
- provide information on federal regulation and policies as they might impact both international and interprovincial trade in electricity;

- ensure that such federal regulations and policies are fundamentally sound, consistent and stable to allow inter-utility trade to grow. In particular, ensure that any measures taken to encourage interprovincial trade do not disturb or cause potential problems concerning international trade;
- participate in establishing procedures to enhance inter-utility cooperation and trade including transmission access and wheeling. (Transmission Access and Wheeling is the subject of a companion report by the Board);
- assist in developing the basic economic assumptions, parameters etc. to be used in regional system planning to ensure that all scenarios are studied on a common basis; and
- facilitate resolution of disputes involving electricity trade and wheeling, both international and interprovincial.

7.8 **Conclusions**

This review has indicated that significant additional benefits could be obtained through greater inter-utility cooperation. This could be achieved most readily by the utilities and other interested parties working together, on a voluntary basis with the objective that all parties benefit. Only as a last resort, when all other avenues have been exhausted, should mandated solutions be considered to resolve disputes concerning international trade, and international and interprovincial wheeling.